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Standards of Practice Manual for the Solvent Refined Liquefaction Process

Hittman Associates, Inc, Columbia, Md

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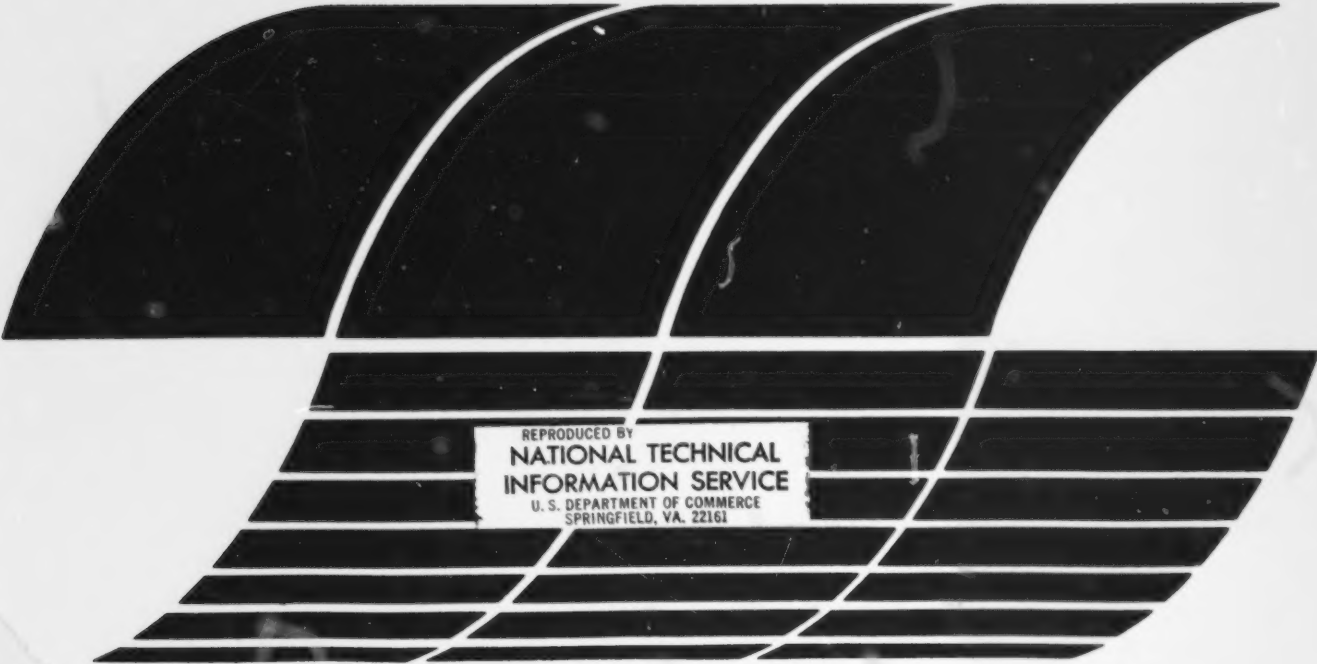
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Standards of Practice Manual for the Solvent Refined Coal Liquefaction Process

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Standards of Practice Manual for the Solvent Refined Coal Liquefaction Process

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ABSTRACT

This Standards of Practice Manual provides an integrated multimedia assessment of control/disposal options, emissions, and environmental requirements associated with a hypothetical 50,000 barrel/day (7,950 cubic meters per day) Solvent Refined Coal (SRC) facility producing gaseous and liquid fuels (SRC-II mode).

An overall outline of the basic system is provided including module descriptions, and summaries on pollution control practices and costs. The manual also provides a survey of currently available and developing control/disposal practices that may be applicable to waste streams from coal liquefaction technologies. In the detailed definition of the basic system, modules are described in detail, and input and output streams are quantified. Applicable control/disposal practices are specified in accordance to waste stream characteristics and pertinent environmental requirements. For each treatment option, capital and operating costs are given along with estimated emissions after treatment. Subsequently, levels of specific pollutants in quantified waste streams are compared to Multimedia Environmental Goals (MEG's) as developed by EPA's IERL-RTP. Finally, emission variations in solid and liquid SRC production are discussed.

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LIST OF ABBREVIATIONS

ADA	---	anthraquinone disulfonic acid; or salt of
API	---	American Petroleum Institute
BBL/D	---	barrels per day
BOD	---	biochemical oxygen demand
BOD ₅	---	five day biochemical oxygen demand
COD	---	chemical oxygen demand
DEA	---	diethanol amine
EOD	---	elimination of discharge
EPC	---	estimated permissible concentration
GPD	---	gallons per day
LD ₅₀	---	lethal dose, 50 percent kill
LPG	---	liquified petroleum gas
MATE	---	minimum acute toxicity effluent
MEA	---	monoethanol amine
MEG	---	multimedia environmental goal
MGD	---	million gallons per day
NO	---	nitric oxide
NO _x	---	oxides of nitrogen
PAH	---	polyaromatic hydrocarbons
PNA	---	polynuclear aromatics
ROM	---	run of mine
SNG	---	synthetic natural gas
SO _x	---	oxides of sulfur
SRC	---	solvent refined coal
TLV	---	threshold limit value
TPD	---	tons per day
VSS	---	volatile suspended solids

1.0 SUMMARY

This Standards of Practice Manual provides a multimedia summary of environmental requirements guidelines and control/disposal options applicable to commercial Solvent Refined Coal (SRC) plants.

For the purposes of this manual a conceptual 50,000 bbl/day (7,950 m³) equivalent SRC facility producing liquid fuel (SRC-II mode) was located on the Wabash River in White County, Illinois. This site was selected because of its accessibility to large reserves of a compatible raw coal feed (Illinois #6), sufficient quantities of water, and an expressed interest by the state of Illinois in coal conversion processes.

Costs associated with the controls are delineated and best practices identified. Based on a preliminary assessment of quantities and constituents in SRC waste streams, it appears promising that conventional control equipment can be utilized to achieve compliance with emission standards. Costs for control equipment are significant, but do not appear to be prohibitive.

Environmental standards are determined (utilizing existing local, state and federal regulations) for such industries as petroleum refineries and coal-fired steam electric power plants, and the basic SRC process matched with appropriate control units. Emissions after controls are compared with Multimedia Environmental Goals (MEG's), and a number of areas are found to exist in SRC processing in which specific constituents discharged exceed the MEG's.

In coal preparation - specifically in coal receiving and crushing - chromium, aluminum and, in some cases, arsenic are found to be emitted in concentrations significantly higher than the MEG's. Chromium and vanadium exceed MEG values by factors of less than 10 in air emissions from steam generation. Gasifier slag contains metals that are excessive, including chromium, cobalt, nickel, barium, arsenic, tin, zinc and selenium. Metals in wastewater effluent are also higher, including magnesium, nickel, scandium and barium.

2.0 Introduction

This manual provides a multimedia summary of environmental requirements, guidelines and control disposal options applicable to Solvent Refined Coal (SRC) plants. The SRC process is summarized and control/disposal modules are identified. The cost of controls are included and best practices are noted. Existing applicable environmental standards are identified. Finally, the basic process for SRC is matched with appropriate control technologies.

The basis for this study is a hypothetical commercial SRC facility producing a liquid fuel (SRC-II mode) at a rate equivalent to 50,000 bbl/day (7,950 m³/day) of crude oil. The plant is located on the Wabash River in White County, Illinois. This site was selected because of its proximity to large reserves of a process compatible raw coal feed, Illinois #6; the availability of an adequate water supply, and an expressed interest by the State of Illinois in coal conversion.

The initial portion of the report provides a description of the overall process. A basic flow sheet showing all processing steps was developed from existing design and economic studies and pilot plant data. This flow sheet identifies the processes and groups them into operations or system modules. The flow sheet identifies all relevant process waste streams. Streams entering and leaving each system module are identified in terms of quantity and composition. Any waste streams that have to be treated by control/disposal measures are characterized in detail. For these streams, the characterization includes quantity, conditions, composition, and identification of the components that must be treated to comply with environmental regulations. The quantities, concentrations and forms of the components are estimated to the fullest extent possible.

A completed version of existing environmental regulations, standards and guidelines is also included in this manual. Regulations imposed by Federal, Local, and State of Illinois authorities are discussed. Regulations from other states where liquefaction facilities might be constructed are also compiled.

There are no existing regulations specifically directed toward SRC facilities. Limits for related industries, such as oil refineries, petrochemical processing plants, and coal-fired steam electric plants, are selected to predict how SRC plant regulations are likely to appear.

Control/disposal practices are identified as potential treatments for waste streams to meet these environmental requirements. However, they do not constitute matching a control to a stream, but rather serve as guide for more detailed specification of control equipment. Estimates of the necessary quantities of treatment chemicals, steam, stripping gases, and fuel are also included.

An economic evaluation of each control disposal option is also included. Capital costs for the controls are based upon the type and size of the equipment required. Operating expenses are based on the cost of materials, energy, and manpower. Those control/disposal practices identified as being potentially applicable are studied in greater detail. After determining ranges of operating parameters and performance characteristics, options found to be unsuitable for controlling the waste streams under study are eliminated from further considerations. These characteristics are determined from available sources such as vendors, developers, technical literature, handbooks and licenses. When information is not available, engineering calculations and estimates of performance are used. Commercial developmental control systems proven to be both technically and economically practical are identified. Control/disposal costs for these various options are tabulated.

Component emissions levels after controls are compared with Multi-media Environmental Goals (MEG's). Emissions exceeding the MEG's are noted.

Differences between the SRC-I (solid product) and SRC-II (liquid product) processes are identified with regard to process design and potential emissions; however, additional information is required to quantitatively assess the differences in emissions.

Finally, a glossary is provided for the definition of terms that are not defined in the text.

3.0 Outline of Basic System

3.1 Introduction

The Solvent Refined Coal (SRC) system utilizes a non-catalytic direct-hydrogenation coal liquefaction process. It converts high sulfur and ash coal into clean-burning gaseous, liquid, and/or solid fuels. There are two basic system variations: (1) SRC-I, which produces a solid coal-like product of less than 1 percent sulfur and 0.2 percent ash; and (2) SRC-II, which produces low sulfur fuel oil (0.2-0.5 percent sulfur) and naphtha product. Both system variations produce significant quantities of gaseous hydrocarbons, which are further processed in the SRC system to synthetic natural gas and liquified petroleum gas products. Some constituents that are formed during the hydrogenation reaction are recovered as by-products. These include sulfur, ammonia, and phenol.

This Standards of Practice Manual has been aimed primarily at the SRC-II system, which at this point in time seems to be the most promising alternative. For the purposes of research, a theoretical 50,000 bbl/day (7,950 cubic meters per day) SRC-II commercial facility has been designed. The design is limited to showing basic process and waste flows, and major pieces of equipment.

To facilitate an understanding of the basic components of the SRC system, a modular approach is taken. In the modular approach, the SRC-II system is subdivided into operations. Each operation is accomplished by carrying out a group of processes, a process being the smallest unit of the overall system. Auxiliary processes perform functions incidental to the functions of system operations. All processes may be represented visually by process modules, which display process input and output stream characteristics. Sets of process modules may be used to describe SRC system operations. The overall SRC system or the entire coal liquefaction energy technology.

Pollution control/disposal processes are not entirely amenable to the modular approach. For example, a dust collection system for a dust stream from coal preparation would fit into the modular approach while techniques for solid waste disposal encompass the SRC system as a whole. Those control/disposal practices that fit the modular approach will be discussed as such, while the more general areas will be discussed under separate titles in the text.

The basic SRC system is described using the modular approach in the following section. A brief summary of the most applicable pollution control options on a modular basis is given in the section on control/disposal practices. The more general control/disposal techniques are also summarized in this section. Cost data for these recommended control/disposal practices is summarized in the section on control/disposal costs.

3.2 System Modules

The SRC-II system is divided into eleven system modules. These include coal preparation, hydrogenation, phase (gas) separation, solids separation, fractionation, hydrotreating, solidification, hydrogen generation, gas purification, cryogenic separation, and auxiliary facilities. The first six modules are considered basic system modules, while the remaining four are considered supporting operations. Figure 1 depicts the overall flow pattern for the SRC-II process including both process and waste flow streams. Figure 2 presents major inputs and outputs of the SRC-II system.

3.2.1 Coal Preparation Module

Coal preparation includes coal receiving, storage, reclaiming and crushing, cleaning, drying, and pulverizing, and slurry mixing. These processes, excluding slurry mixing, are designed to clean and size-reduce the coal to levels acceptable for use in the SRC liquefaction process. The slurry mixing process mixes the processed coal with recycled process solvent prior to entering the hydrogenation reactor. Dryer stack gases, refuse, and wastewaters heavily laden with suspended solids constitute major wastes in this module.

3.2.2 Hydrogenation Module

Hydrogenation consists of a slurry preheater and a hydrogenation reactor. This module constitutes the key operation within the SRC system where coal is transformed into liquid products. All other subsequent operations focus on refining the products generated in this module. Flue gas represents the only significant waste discharged from the module.

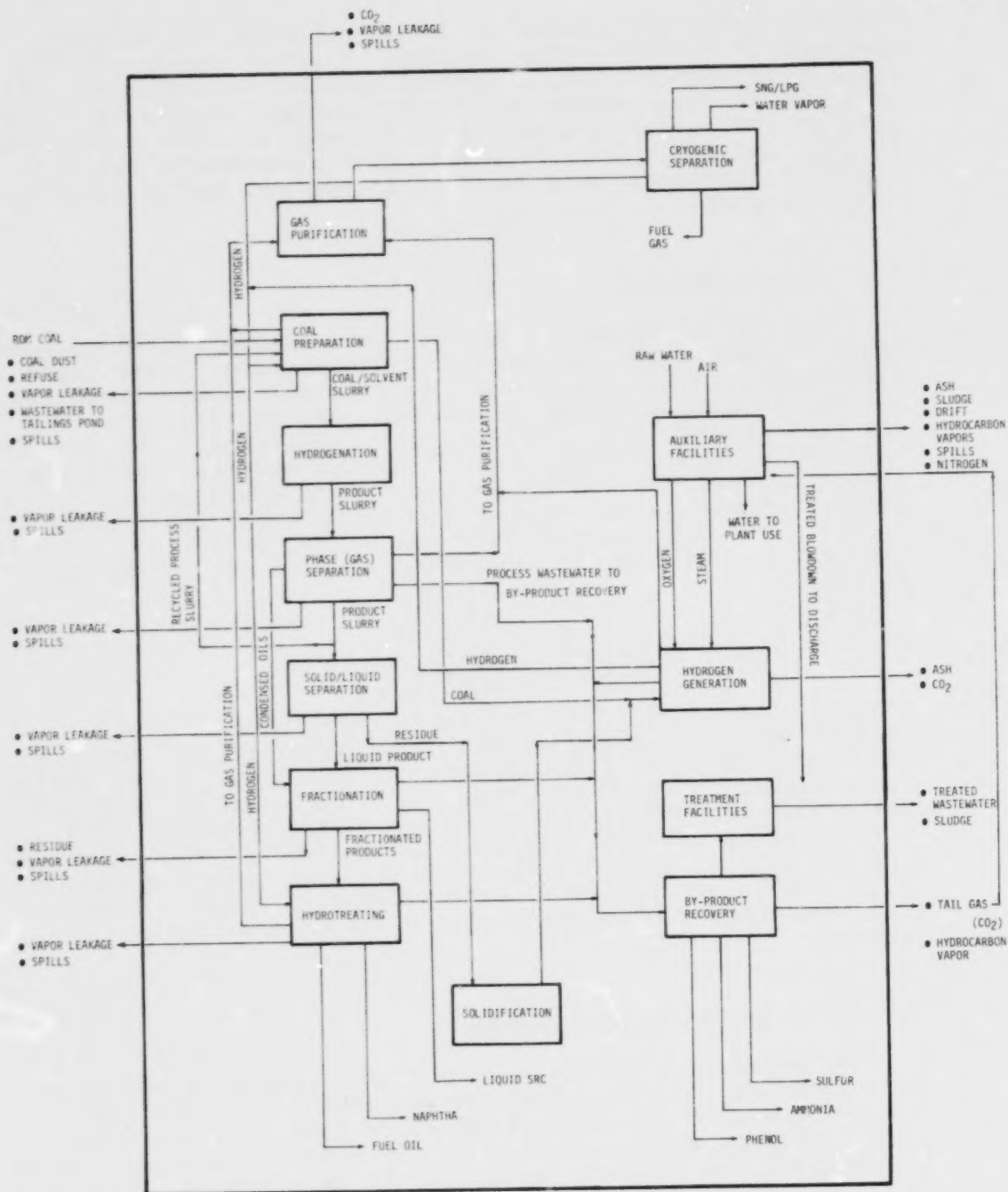


Figure 1. SRC-II System Overall Flow Diagram

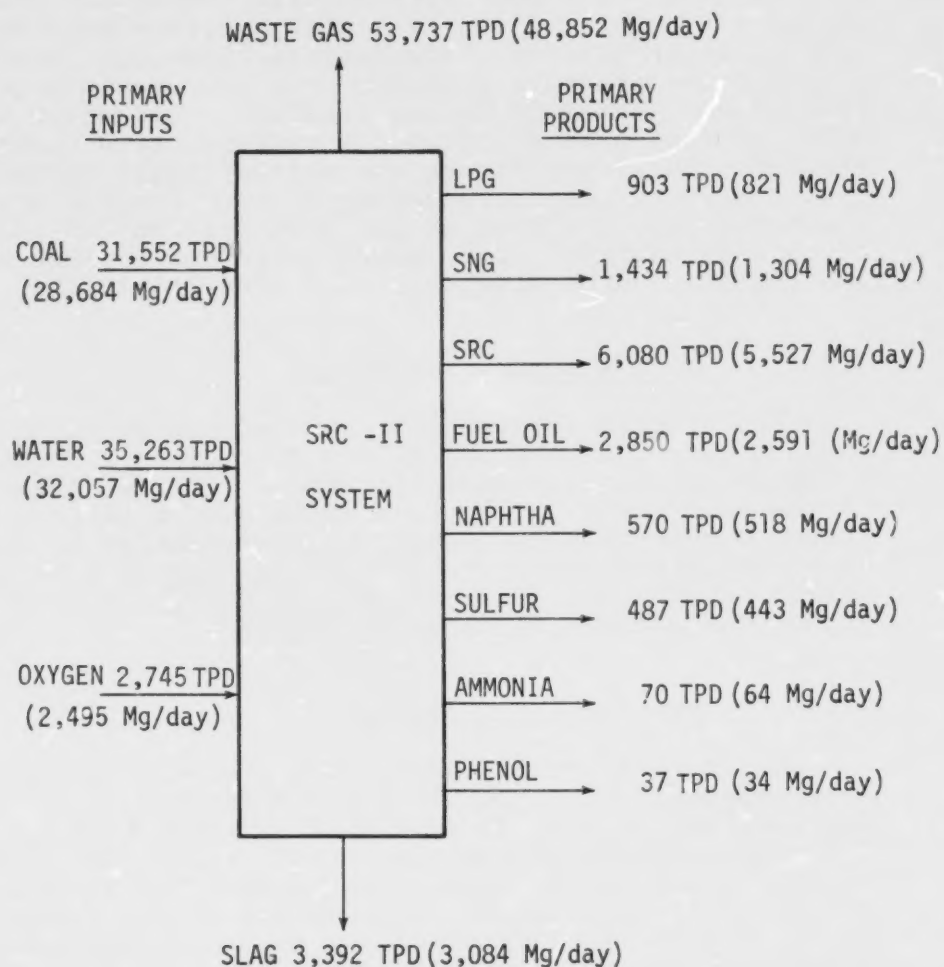


Figure 2. Overall Material Balance for a 50,000 bbl/day (7,950 m³/day) SRC-II System

3.2.3 Phase (Gas) Separation Module

There are a number of processes within the phase (gas) separation module including: high pressure separation, condensate separation, intermediate flashing, intermediate pressure condensate separation, and low pressure condensate separation. These processes separate hydrocarbon vapors and other gaseous products from the hydrogenation reactor effluent slurry and direct the solids/liquid portion of the coal slurry to other processing areas. Process streams from the module are directed to gas purification, solids separation, and fractionation. Waste emissions include accidental and fugitive vapor discharges and material spills.

3.2.4 Solids Separation Module

The processes within the solids separation module include feed flashing and solids separation. These processes separate the residue (solids) stream from the liquid portion of the feed stream. The residue is routed to the solidification module to be prepared for gasification or disposal. No wastewater streams are discharged from this module under normal operations. Intermittent discharges include fugitive vapors and accidental material spills.

3.2.5 Fractionation Module

The fractionation module consists of a vacuum flash and an atmospheric distillation functioning to (1) separate the high boiling liquid SRC product from lower boiling fractions; (2) combine light streams for fractionation into light products; and (3) separate wash solvent for recycling to the solids separation module. Evacuation of the flash vessel may be accomplished by steam ejector which produces a continuous wastewater stream or vacuum pump which produces a gaseous waste stream. Preheater flue gas constitutes the only other continuous waste stream. Intermittent discharges include fugitive vapors and accidental material spills.

3.2.6 Solvent Hydrotreating Module

The solvent hydrotreating module consists of hydrogen addition, catalytic reaction, flashing, oil-water separation, and stripping. Solvent hydrotreating involves the reaction of raw hydrocarbon streams with hydrogen to remove con-

taminants such as organic sulfur and nitrogen compounds, and to improve combustion characteristics. Flue gas from the solvent preheater and wastewater from an oil-water separator are the only continuous waste streams.

3.2.7 Solidification Module

The function of the solidification module in the SRC-II system is to cool the residue into a solid suitable as a feed to the gasifier. This function is accomplished by feeding the liquid residue onto a Sandvik belt cooler. The cooled solid residue is scraped off the belt with a knife and routed to gasification. Emissions from the solidification module include vapors and particulates from the belt cooling process. Also, a solid waste stream results from the disposal of residue in excess of gasifier requirements.

3.2.8 Gas Purification Module

Contaminated gases from phase (gas) separation and solvent hydrotreating modules are purified by acid gas removal. Contaminants removed include hydrogen sulfide, carbon disulfide, carbon dioxide, and carbonyl sulfide. The only continuous waste stream is the wastewater from the amine regenerator section of acid gas removal unit. Intermittent wastewater streams are accidental spills and backwash of the amine filter. Atmospheric emissions include gas leakage from sumps and storage vents and fugitive emissions during maintenance operations.

Cryogenic Separation Module

Gas from the purification module flows to a series of cryogenic units within this module, where the heavier hydrocarbon gases are cooled and condensed to form a liquid. The resulting liquid stream is charged to a fractionation tower where various hydrocarbon products are removed. The remaining gases are flashed and flow to another series of cryogenic units and a de-ethanizer column, where the liquid product is removed and overhead gases flow to another series of cryogenic units.

Purified gas is separated into hydrogen, synthetic natural gas, liquified petroleum gas, and light oils in this module. Wastewater from light oil distillation is the only waste stream from this module.

3.2.9 Auxiliary Processes Module

Auxiliary processes include ammonia recovery, phenol recovery, sulfur recovery, oxygen generation, raw water treatment, cooling towers, steam and power generation, product and by-product storage, wastewater treatment, and hydrogen production. These processes recover by-products from waste streams, furnish utilities (steam, water, power), and furnish feed materials (oxygen, hydrogen). Major waste streams include wastewater from ammonia stripping towers; wastewater from the phenol extraction towers; off-gas from the sulfur recovery absorber; gaseous waste nitrogen from oxygen generation; sludges from raw water treatment; wastewater resulting from blowdown of cooling towers; flue gases and ash from steam and power generation; spills, fugitive vapors and dust from product and by-product storage; treated wastewater and sludges from wastewater treatment; and slag, spent catalyst, spent scrubbing solutions and flue gases from hydrogen production.

3.3 Control/Disposal Summary

Table 1 presents a complete list of suggested control/disposal practices for a 50,000 bbl/day (7,950 cubic meters per day) theoretical SRC-II system. Waste streams and suggested control measures are presented on a modular basis. The wastewater treatment and flare systems do not easily fit into the modular approach, since they apply to combined waste streams from several modules. Therefore, they are listed separately in Table 1. Suggested control/disposal practices were based on the information developed in Section 5 entitled "Detailed Definition of Basic System." Selection of the suggested process from the alternatives presented in Section 5 was based on removal efficiencies, operation and maintenance characteristics, and capital and operating costs.

3.4 Control/Disposal Costs

A summary of capital and operating costs of control/disposal practices for a theoretical 50,000 bbl/day (7,950 cubic meters per day) SRC-II facility is presented in Table 2.

Cost data was based on literature and vendor information. Equipment sizing was based on calculated flow rates and concentrations of waste streams. In cases where waste flows could not be calculated, such as with flare systems, equipment sizing and cost estimation was developed by comparison with pollution control systems in oil refineries having a similar throughput. Cost adjustments were made using the six-tenths factors (see Glossary).

From Table 2, it has been calculated that about 32.2 million dollars of fixed capital investment would be spent on pollution control, (as of July 1977). Using Ralph M. Parsons Company's 1973 estimate of capital equipment cost for a 10,000 TPD (9,091 Mg per day) SRC-II plant, it has been estimated that roughly 179.6 million dollars would be spent on major equipment for a 50,000 bbl/day (7,950 m³/day) SRC-II plant (as of July 1977).

Using these estimates it has been calculated that about 18 percent of the total equipment cost for a commercial size SRC-II facility would be dedicated to pollution control/equipment.

3.5 Variations Resulting From Regional Siting Factors

The location of an SRC facility in other regions of the United States can affect the process design, water consumption, volume and composition of wastes discharges, and pollution controls. Those factors which may be responsible for regional variations are raw coal composition, water availability, climate, and federal, state, and local regulations regarding waste emissions to land, air, and water. A detailed discussion of these factors is given in Chapter 5.0.

TABLE 1. SUGGESTED CONTROL/DISPOSAL PRACTICES
FOR THE SRC-II SYSTEM*

Module/Stream	Major Waste Constituents	Quantity (TPD)	Suggested Control Measures
<u>Coal Preparation</u>			
Coal receiving	Coal dust	8	Cyclone and baghouse
Storage	Coal dust	8	Polymer coating
Storage	Runoff	74	Tailings pond
Reclaiming and crushing	Coal dust	8	Cyclone and baghouse
Dryer stack gas	Particulates	32,842	Baghouse
Water recycle system	Coal/water slurry	3,432	Tailings pond
Crushing and cleaning	Tramp iron & refuse	8,484	Mine burial
Dryer flue gas	Carbon dioxide, nitrogen	3,961	Vented to atmosphere
<u>Hydrogenation</u>			
Flue gas	Carbon dioxide, nitrogen	14,758	Vented to atmosphere
Hydrocarbon vapors	Hydrocarbons	not quantified	Flare system
<u>Wastewater Treatment</u>	Ammonia, hydrogen sulfide, hydrocarbons	4,201	Extended aeration with recycle
<u>Flare System</u>	Hydrocarbons	not quantified	Vented to atmosphere
<u>Phase Gas Separation</u>			
Hydrocarbon vapors	Hydrocarbons	not quantified	Flare system

TABLE 1. SUGGESTED CONTROL/DISPOSAL PRACTICES
FOR THE SRC-II SYSTEM* (Continued)

Solids Separation

Flue gas	Carbon dioxide, nitrogen	10,777	Vented to atmosphere
Hydrocarbon vapors	Hydrocarbons	not quantified	Flare system

Fractionation

Flue gas	Carbon dioxide, nitrogen	2,291	Vented to atmosphere
Hydrocarbon vapors	Hydrocarbons	not quantified	Flare system

Solvent Hydrotreating

Flue gas	Carbon dioxide, nitrogen	1,697	Vented to atmosphere
Hydrocarbon vapors	Hydrocarbons	not quantified	Flare system

Solidification

Residue	Mineral matter from coal	2,377	Landfill
Hydrocarbon vapors and particulates	Mineral matter and hydro- carbons	not quantified	Landfill

Gas Purification

Hydrocarbon vapors	Hydrocarbons	not quantified	Flare system
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Cryogenic Separation

Hydrocarbon vapors	Hydrocarbons	not quantified	Flare system
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Hydrogen Production

Scrubber gas	Carbon dioxide	752	Vent to atmosphere
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TABLE 1. SUGGESTED CONTROL/DISPOSAL PRACTICES
FOR THE SRC-II SYSTEM* (Continued)

Flue gas from gasifier	Carbon dioxide, nitrogen	1,128	Vent to atmosphere
Spent MEA solution	MEA	4	Landfill
Slag from gasifier	Mineral matter	1,692	Landfill
Hydrocarbon vapors	Hydrocarbons	not quantified	Flare system
<u>Auxiliary Facilities</u>			
Ammonia recovery	None	---	---
Phenol recovery	None	---	---
Sulfur recovery	Light hydrocarbons, hydrogen sulfide, nitrogen oxides	12,077	Direct flame incineration
Oxygen generation	Nitrogen	9,997	Vented to atmosphere
Raw water treatment	Calcium carbonate	407	Landfill
Cooling towers	Treated blowdown (metals and dissolved solids)	762	Discharge to river
Steam and power generation	Flue gas (SO ₂ , NO _x , CO, particulates)	13,145	MgO scrubbing
Product Storage	Hydrocarbon vapors	not quantified	Flare system

*Only English units are presented due to space limitations.

TABLE 2. CONTROL/DISPOSAL COSTS FOR A
50,000 bbl/day (7,950 m³/day)
SRC-II SYSTEM

Module/Stream	Capital Control Costs (\$1000)	Annual Operating Costs (\$1000)
<u>Coal Preparation</u>		
Coal receiving	15.0	N.A.
Storage (coal dust)	18.0	432.6 - 561.0
Storage (runoff)	30.0	N.A.
Reclaiming & crushing	60.0	N.A.
Dryer stack gas	1000.0	N.A.
Water recycle system	Same as Storage Runoff	
Crushing and cleaning	N.A.	2500.0 - 15,300.0
Flue gas	None	None
<u>Hydrogenation</u>		
Flue gas	None	None
Hydrocarbon vapors	None	None
<u>Phase Gas Separation</u>		
Hydrocarbon vapors	None	None
<u>Solids Separation</u>		
Flue gas & hydrocarbon vapors	None	None
<u>Fractionation</u>		
Flue gas & hydrocarbon vapors	None	None
<u>Solvent Hydrotreating</u>		
Flue gas & hydrocarbon vapors	None	None
<u>Solidification</u>		
Residue	N.A.	870.0 - 6900.0
Hydrocarbon vapors and particulates	None	None

TABLE 2. CONTROL/DISPOSAL COSTS FOR A
50,000 bbl/day (7,950 m³/day)
SRC-II SYSTEM (CONTINUED)

Module/Stream	Capital Control Costs (\$1000)	Annual Operating Costs (\$1000)
<u>Gas Purification</u>		
Hydrocarbon vapors	None	None
<u>Hydrogen Production</u>		
Scrubber gas & flue gas	None	None
Slag & MEA solution	N.A.	189.0
Hydrocarbon vapors	None	None
<u>Auxiliary Facilities</u>		
Ammonia recovery	None	None
Phenol recovery	None	None
Sulfur recovery	572.0	4083.0
Oxygen generation	None	None
Raw water treatment	180.9	285.8
Cooling towers	None	None
Steam & power generation*	29040.0	13140.0
Product storage	None	None
<u>Wastewater Treatment</u>	1136.5	121.0
<u>Flare System</u>	208.2	4.5
TOTAL	32,260.6	21,504.9-40,463.3

* MgO scrubbing used for the purposes of cost estimating.

4.0 Existing Environmental Requirements

4.1 Introduction

No legislation currently exists directly pertinent to the SRC or other liquefaction systems. Prior to commercialization such legislation may be necessary at the federal, state and local levels. A review of existing standards and guidelines provides an idea of long range goals in the area of environmental policy. Additionally, existing standards governing related fossil fuel technologies could serve as the foundation on which standards for liquefaction facilities will be based. However, at this time it is impossible to project how stringent and how comprehensive environmental regulations will be specific to commercialized SRC or other liquefaction systems.

4.1.1 Federal Policy

National primary and secondary ambient air quality standards have been established for several types of emissions including particulates, hydrocarbons and sulfur oxides. These standards are summarized in Table 81 found in the appendices.

Additionally, standards for new sources have been established. Specifically the standards for coal preparation plants, petroleum liquid storage vessels, and fossil fuel fired steam generators may be similar to the standards which will be established for corresponding areas of SRC production facilities. The steam generator data may be more applicable to SRC utilization than it is to production. New source standards possibly applicable are presented in Table 82 of the appendices.

National emission standards for air pollutants deemed hazardous are established in conjunction with EPA. Standards currently exist for mercury, beryllium and asbestos. Although none of these is likely to affect SRC production, future standards for hazardous air pollutants may be applicable.

The Federal Water Pollution Control Act has established long range national goals to limit point source effluent concentrations. The act requires "application of the best practicable control technology currently available" not later than July 1, 1977. Six years later "application of the best available technology economically achievable" will be required to meet the national goal of "eliminating the discharge of all pollutants."

Effluent guidelines and standards exist for several industries which have operations similar to SRC liquefaction. Table 83 of the appendices includes standards and guidelines for coal preparation and storage facilities and coking operations, although coking operations are more directly applicable to liquefaction processes based on pyrolysis. In addition, a comprehensive system of standards has been established for petroleum refinery operations. Effluent limitations for refineries are functions of overall refinery size and the capacities and pollution potentials of the refinery operations. A similar system may be developed for liquefaction plants, the factors of plant size and process type making the effluent limitations as equitable as possible.

The characterization of solid waste materials leaving SRC conversion plants is incomplete. It is possible that hazardous wastes are present. For this reason, subsequent discussions of solid waste disposal shall include hazardous waste disposal although the necessity of such measures is not certain.

Guidelines for land use and ultimate disposal of solid wastes are not as advanced as the legislation governing emissions to air and water. The EPA requirements and recommendations most applicable to SRC generated solid wastes are described in Table 84 of the appendices.

Not all constituents of the products, by-products and wastes generated by the SRC system are known. The Toxic Substances Control Act was established to provide regulation and testing of new and existing materials which could cause unreasonable health and environmental consequences. Testing may be prescribed for cumulative or synergistic effects, carcinogenicity, mutagenicity, birth defects and behavioral disorders. Should any SRC system components be characterized as toxic, the development of technology capable of isolating and disposing of those components will be necessary. Since continuing coal liquefaction research has not yielded a complete characterization of the SRC system components and complete determination of substances and concentrations of those substances which should be considered toxic, the potential impact of SRC system components has been difficult to assess.

4.1.2 Environmental Policy of the State of Illinois

The site for the hypothetical SRC plant considered in this study is located on the Wabash River in White County, Illinois. Environmental legislation in Illinois is among the most comprehensive of all states having the large coal reserves needed to site commercial SRC facilities. Both air quality standards and stationary source standards have been promulgated. Water quality standards are dependent upon water use classification.

Promulgated emission standards most likely to be applicable to SRC plants in the future include particulates, carbon monoxide, nitrogen oxides, sulfur dioxide, and fugitive particulate matter. Effluent limitations of interest include heavy metals, phenols, BOD₅, and suspended solids.

Pertinent sections of the Illinois Pollution Control Board Rules and Regulations may be found in the appendices.

4.1.3 Environmental Policies of Other States

Appendix B includes the environmental policies of 16 states other than Illinois which, due to their abundant coal reserves, are potential sites of commercial SRC facilities. Emphasis is placed on standards and guidelines more stringent than their federal counterparts or dealing with areas for which no federal legislation currently exists. For example the New Mexico legislation for coal gasification plants limits hydrogen sulfide emissions to less than 10 ppm. Since this is the only known regulation pertaining to hydrogen sulfide emissions from an industrial complex, it has been used as a guide to assess emissions from the hypothetical SRC facility. Some local requirements different from those of the states are also discussed.

5.0 Survey of Control/Disposal Practices

5.1 Introduction

This section presents a survey of currently available and developing control/disposal practices that may be applicable to a commercial SRC facility. In the gas, liquid, and solids treatment sections, stream characteristics are first discussed with respect to their effect on control/disposal options. Next, pollution control equipment applicable to gas, liquid, and solid waste streams is discussed. Finally, the most feasible alternatives for the treatment of waste streams specific to SRC production are developed. More practice-oriented pollution control/disposal options are included in sections on final disposal, fugitive emissions control, and accidental release technology. Process-oriented pollution control measures are discussed in fuel cleaning and combustion modification, as well as in accidental release technology and fugitive emissions control. The last section deals with regional variations, such as climate and regulations, and how they may affect control/disposal specification.

The following text should provide the coal liquefaction engineer with a working knowledge of the available and developing control/disposal practices, limitations and trade-offs, and control/disposal options selected to apply to the treatment of wastes generated by a commercial SRC facility.

5.2 Gas Treatment

5.2.1 Gas Stream Characteristics

The proper selection of control/disposal modules is dependent on a number of gas stream characteristics. Stream temperature, pressure, combustibility, reactivity, flow rate, flow rate variability, grain loading, and particle size are the main factors influencing equipment selection.

Stream temperature will influence the volume of the carrier gas and the materials of construction. The volume of the carrier gas will influence size and cost of equipment and the contaminant concentration per unit volume. Viscosity, density, and other gas properties are temperature dependent. Adsorption processes are generally exothermic

and are therefore impractical at higher temperatures. Dust resistance and dielectric strength of gas both are temperature dependent and become factors in electrostatic precipitators. Wet processes cannot be used with high temperatures because of losses from boiling and evaporation. Filter media can be used only in the temperature range at which they are stable.

Gas pressure much higher or lower than atmospheric pressure requires designing control equipment as a pressure vessel. High pressure is especially compatible with high efficiency scrubbers, since the available pressure can be used to overcome the high pressure drop across the scrubber. In absorption, high pressure facilitates removal and is required in some situations.

Combustible carrier gases must be above or below the explosive limits with respect to an admixture of the gas with air. The use of water scrubbing or absorption may minimize explosion hazards. Electrostatic precipitators are deemed unacceptable for treatment of combustible gases, since they tend to spark and may ignite the gas.

Reactivity of a gas may require special construction materials. Relatively compact control modules, such as scrubbers, may be advantageous because corrosion-resistant components costing relatively less, may be used.

The flow rate of the carrier gas will directly influence the size of the equipment and the velocity of the gas through the equipment. The size of the equipment should be minimized for economic reasons. The relationship between equipment size and gas velocity should be optimized when selecting equipment. Two considerations are apparent: (1) reduction of equipment size increases pressure drop and thereby increases power requirements for a given amount of gas; and (2) the effect of gas velocity on removal efficiencies must be considered. In inertial separators, higher velocities result in greater removal efficiencies up to the point of turbulence. For gravity settlers, flow velocity determines the minimum particle size that can be removed. In venturi scrubbers, removal efficiency is directly proportional to gas velocity.

Variations in flow rate also may influence equipment selection. Filters adapt well to extreme flow variations, although they also are subject to pressure drop variations. In other control systems, a variation in flow will change the removal efficiency unless the equipment has been designed for varying flow conditions. Two control units in series having efficiency versus flow rate curves which are complementary provide a feasible solution.

The influence of grain loading may vary with control units. For example, cyclones are quite efficient at high dust loadings, but the efficiency of electrostatic precipitators, another type of control unit, is reduced.

Particle size distribution is one of the most important factors when considering particulate control equipment selection and performance. Inertial separators usually have low removal efficiencies (50-90%) for particles under 20 microns, while impingement separators (baghouses) and precipitators may exhibit almost 100 percent removal of particles in the 0-1 micron size range. Thus, particle size distribution of the pollutant stream should be known before selecting control equipment.

5.2.2 Particulate Controls

5.2.2.1 Dry Collectors

Dry collectors separate particulates from the gas stream either by gravity settling, impingement, and/or inertial action. The major classes of dry collectors include gravity settling chambers, cyclones and multicyclones, and dynamic precipitators.

Gravity settling chambers are large, rectangular chambers with a gas inlet at one end and an outlet at the opposite end. Settling occurs due to a reduction in gas velocity. Industrial applications of settling chambers are limited to the removal of particulates over 40 microns in diameter. Their use is limited to pretreatment to remove coarse and abrasive particles for the protection of more efficient collection equipment that may follow. Performance is described by the following equation (1):

$$P = 100 \frac{U_t L}{HV}$$

where* P = efficiency of unit (% wt particles settling at U_t)

U_t = settling velocity of dust (ft/sec)

L = length of chamber (ft)

H = height of chamber (ft)

V = velocity of gas (ft/sec)

The settling velocity is calculated by assuming Stoke's law, as follows:

$$U_t = g_c D_p^2 \frac{(\rho_s - \rho)}{18 \mu}$$

where* D_p = particle diameter (ft)
 μ = gas viscosity [lb m/(ft)(sec)]
 g_c = 32.2 (ft/sec²)
 ρ_s = particle density (lb/ft³)
 ρ = gas density (lb/ft³)

Minimum particle size collected at 100 percent efficiency is determined as follows (1):

$$D_p = \sqrt{\frac{18 \mu H V}{g_c L (\rho_s - \rho)}}$$

where* D_p = minimum particle diameter collected at 100% efficiency (ft)

*Metric conversion factors are given in Appendix A.

Cyclones and multicyclones separate particles by centrifugal force. In the cyclone, the particulate gas stream enters the cone-shaped collector tangentially and at low velocities. The particulate-laden gas mixture flows downward in a spiral of increasing velocity. The inertial force separates the dense particles from the gas. As the gas travels down the narrowing core, the creation of a vortex causes the gas to reverse its downward path. This creates a vacuum which carries the clean gas out of the top of the collector. Particles down to 10 microns can be effectively removed. The multicyclone consists of parallel rows of small diameter cyclones, provided with a common inlet tube. The particulate-laden gas is caused to swirl by revolving vanes located at the tube entrance. A vortex is formed and the clean gas leaves the collector through the inner tube; the particulates collect in a dust collector beneath the multicyclone.

The separation efficiency of cyclones increases with an increase in grain loading, particle size, and gas velocity. Design characteristics, such as cyclone body length and inner wall smoothness, will affect particulate removal efficiency. Cyclones up to 9 inches (23 cm) in body diameter are considered high efficiency cyclones. Cyclones in general provide low efficiencies for pollution control and are least expensive. Multicyclones are small diameter cyclones in series designed to handle large gas flow rates. Efficiencies of particulate removal with respect to particle size are given in Table 3.

TABLE 3. EFFICIENCY OF CYCLONES (1)

Particle Size	Efficiency Range (% Collected)	
	Conventional	High Efficiency
Less than 5	Less than 50	50-80
5-20	50-80	80-95
15-40	80-95	95-99
Greater than 40	95-99	95-99

Where possible, specific calibration curves should be used when evaluating the performance of a cyclone or multicyclone. Some approximate relationships are available where calibrated data are not available.

The cut size (D_{cp}) in a cyclone is the particle size that can be collected at 50 percent efficiency. It can be calculated by the following equation (1):

$$D_{cp} = \sqrt{\frac{9 W_i}{2 \pi N_e V_i (\rho_p - \rho)}}$$

where*

D_{cp} = cut size (ft)

μ = gas viscosity (lb/ft sec)

W_i = inlet width (ft)

N_e = number of effective turns in a cyclone
(5 to 10 in most cases)

V_i = inlet velocity (ft/sec)

$$\begin{aligned}\rho_p &= \text{particle density, (lb/ft}^3\text{)} \\ \rho &= \text{gas density (lb/ft}^3\text{)}\end{aligned}$$

Removal efficiency is highly dependent on gas flow rate in cyclones. Changes in efficiency with respect to flow rate variability can be estimated by the following equation (1):

$$\frac{N_1}{N_2} = q_1/q_2$$

where* N_1 = weight percent collection efficiency at flow rate q_1 .

N_2 = weight percent collection efficiency at flow rate q_2 .

*Metric conversion factors are given in Appendix A.

Dynamic precipitators use centrifugal force generated by rotating impellers to separate particulate matter. They are generally considered more efficient than cyclones; however, specific information on the performance of these units is not available.

5.2.2.2 Electrostatic Precipitators

Electrostatic precipitators operate by using a direct current voltage to create an electric field between a negatively charged discharge electrode and a positively charged collection electrode. As the suspended particles (or aerosols) pass between the electrodes the particles are charged and collected on the oppositely charged electrode. The deposited matter is removed by rapping or washing the electrode. The precipitated material is then collected in hoppers for final disposal.

Electrostatic precipitators exhibit removal efficiencies of 90 to 99.9 percent within a particle range of less than 0.1 microns to 200 microns (1,2). Precipitators have the ability to handle very large flow rates at high efficiencies. They can operate in a wide range of temperatures and pressures, up to 800°C and 50 atmospheres, respectively (1). Their major disadvantages include high initial cost and little adaptability to changing process conditions.

Removal efficiency is directly related to the volumetric gas flow rate, as described by the following equation (1):

$$F = 1 - e^{\frac{(-WA)}{Q}}$$

where*

F = efficiency, decimal evaluation

A = collecting area (ft²)

Q = volumetric flow rate (ft³/sec)

W = drift velocity (ft/sec)

The drift velocity, W, can be calculated by the following equation (1):

$$W = (1 + 1.72 \frac{L}{D_p}) \frac{D_p E_o E_p}{4 \pi \mu}$$

where*

W = drift velocity (feet/sec)

D_p = particle diameter (feet)

L = mean free path of gas (feet)

E_p = precipitation field density (KV/in)

E_o = corona field strength (KV/in)

μ = absolute viscosity of the gas (lb/sec-ft)

*Metric conversion factors are given in Appendix A.

Removal efficiencies are dependent on the temperature and humidity of the gas stream. An increase in humidity and/or a decrease in temperature will cause a decrease in sparkover voltage, i.e., the voltage at which the gas becomes locally conductive. At sparkover voltage there is a dramatic decrease in the electric field strength and hence a large power loss. Such gas streams as dryer off-gases may be too humid to separate particulates by electrostatic precipitation.

5.2.2.3 Bag and Fabric Filters

Baghouses and fabric filters are used for high efficiency removal (up to 99.9%) of particulates from gases. Baghouses and fabric filters, along with inertial dry collectors, share the following characteristics.

- (1) Particulates are collected dry and in usable condition.
- (2) Gases are not cooled or saturated with moisture.
- (3) Solids handling accessories must be properly designed to avoid secondary dust generation.
- (4) Unlike scrubbers, filters do not add moisture to the cleaned exhaust and do not create a plume.
- (5) There is an explosion hazard risk; proper fire protection equipment must be on-site.

There are two major types of bag filters. Envelope-type bags prove maximum surface area per unit volume, but suffer from dust bridging problems and are difficult to change. Tubular bags are open at one end and closed at the other, with the direction of filtering being either inside-out or outside-in. An outside-in design requires a frame to prevent bag collapse and has a shorter bag life. Tubular filter bags are often sewn together to form multibag systems; the major disadvantage is costly bag replacement.

Different gas characteristics require different filter media for proper operation. There are three main filter types: paper filters, woven fabric filters, and felted fabric filters. Paper filters are used for sampling and analysis and clean room use rather than in large industrial units. Woven fabric filters are employed with low air/cloth ratios, generally from 1.5 to 6 cfm/ft² (7.6×10^{-3} to 3.0×10^2 m³/S/m²) (1). Fabric life is a function of operation temperature, frequency and method of cleaning, and properties of particulates and carrier gas. Average life of woven fabric filters ranges from 6 to 18 months. Performance of some filter fabrics are summarized in Table 4 (1). The more efficient felted fabrics are more expensive, but can be utilized with high air/cloth ratios typically 12.1 cfm/ft² (6.1×10^{-2} m³/S/m²) (1). Felted fabrics require thorough cleaning for proper operation.

TABLE 4. CHARACTERISTICS OF FILTER FABRICS (1)

Fibers	Maximum Operating Temperature, °F	Specific Gravity	Physical Resistance					Chemical Resistance					Relative Cost
			Dry Heat	Moist Heat	Abrasion	Sliding	Flaring	Mineral Acids	Organic Acids	Alkalies	Oxidizing Agents	Solvents	
Cotton	180	1.6	G	G	F	G	G	P	G	F	F	E	Low
Dacron	275	1.4	G	F	G	E	E	G	G	F	G	E	Moderate
Orlon	250	1.2	G	G	G	G	E	G	G	F	G	E	Moderate
Nylon	250	1.1	G	G	E	E	E	P	F	G	F	E	Moderate
Dynel	180	1.3	F	F	F	P-F	G	G	G	G	G	G	Moderate
Polypropylene	225	0.9	G	F	E	E	G	E	E	E	G	G	Low
Creslan	275	1.2	G	G	G	G	E	G	G	F	G	E	Moderate
Vycron	300	1.4	G	F	G	E	E	G	G	G	G	E	Moderate
Nomex	450	1.4	E	E	E	E	E	P-F	E	G	G	E	High
Teflon	500	2.3	E	E	P-F	G	G	E	E	E	E	E	High
Wool	200	1.3	F	F	G	F	G	F	F	P	P	F	Moderate
Glass	550	2.5	E	E	P	P	F	E	E	G	E	E	High

E-Excellent G-Good F-Fair P-Poor

*Metric conversion factors are given in Appendix A.

Cleaning methods affect air/cloth ratios significantly. Cleaning by shaking can be accomplished manually or mechanically, intermittently or continuously. Reverse jet cleaning uses compressed air to remove filter cake from the fabric. Reverse air flexing is accomplished by reversing gas flow to cause a filter backwash effect.

Air-to-cloth ratios for coal dust are shown for different types of cleaning mechanisms in Table 5.

TABLE 5. AIR-TO-CLOTH RATIOS FOR COAL DUST (1)

Type of Cleaning	Air/Cloth Ratio	
	cfm/ft ²	m ³ /S/m ² x 10 ⁻²
Shaker	2.5 - 3.0	1.3 - 1.5
Reverse Jet	10 - 12	5.1 - 6.1
Reverse Air Flexing	1.1 - 2.0	0.6 - 1.0

5.2.2.4 Wet Scrubbers

Wet scrubbers comprise a large variety of equipment, the main types being spray chambers, impingement plate scrubbers, venturi scrubbers, cyclone-type scrubbers, orifice-type scrubbers, and packed bed scrubbers. Low pressure scrubbers, such as spray towers collect coarse dusts in the range of 2 to 5 microns. High pressure drop venturi scrubbers are effective at removing 0.1 to 1.0 micron particles at up to 98 percent efficiency (2).

The wet scrubbers remove dust from the carrier gas stream by contacting it with water or a specified scrubbing liquor. The following is a list of the characteristics of wet scrubber technologies (1).

- (1) The flue gas is both cleaned and cooled.
- (2) Stack effluent will contain fines, mists, and steam plume.
- (3) The temperature and moisture content of the inlet gas is essentially unlimited.
- (4) Corrosive gases can be neutralized with proper scrubbing liquor selection.

- (5) Consideration of freezing conditions is important.
- (6) Hazards of explosion are reduced.
- (7) Equipment is relatively compact and capital cost is less than dry collection equipment.
- (8) The equipment is highly efficient in collecting a wide range of particulate sizes.
- (9) Removes simultaneously gaseous pollutants such as sulfur dioxide, hydrogen sulfide, and nitrogen oxides.
- (10) Maintenance cost is lower because of simple design.
- (11) Water utilization is high and is an important consideration in certain areas.

Efficiencies of various scrubbers at different particle sizes are shown in Table 6. Wet scrubbers than can be applied to coal dusts and fly ash control are shown in Table 7.

TABLE 6. EFFICIENCY OF SCRUBBERS AT
VARIOUS PARTICLE SIZES (1)

Type of Scrubber	Percentage Efficiency at		
	50 μ	5 μ	1 μ
Jet-impingement scrubber	98	83	40
Irrigated cyclone	100	87	42
Self-induced spray scrubber	100	94	48
Spray tower	99	94	55
Fluid bed scrubber	99+	98	58
Irrigated target scrubber	100	97	50
Disintegrator	100	98	91
Low energy venturi scrubber	100	99+	96
Medium energy venturi scrubber	100	99+	97
High energy venturi scrubber	100	99+	98

TABLE 7. APPLICABILITY OF VARIOUS WET
SCRUBBERS TO COAL DUSTS AND FLY ASH (1)

Type of Scrubber	Coal Dust	Fly Ash	Collection Efficiency (%)
Elbair scrubber	X	X	99+, 99
Floating bed		X	N.A.
Flooded bed		X	N.A.
Cyclonic		X	96+
Self-induced spray scrubbers	X		N.A.
Mechanically induced spray	X		N.A.
Venturi scrubbers	X	X	96, 99+

N.A. = Not Available

5.2.3 Hydrocarbon Emission Controls

Four types of control technologies that can be employed to treat gas streams containing hydrocarbons are: (1) direct-fired and catalytic afterburners, (2) flares, (3) condensation systems, and (4) adsorption systems.

Direct-fired and catalytic afterburners employ high temperatures to carry out oxidation of organics to carbon dioxide and water. They are applicable to gases with hydrocarbon content below the limit of flammability. In general, catalytic afterburners, with platinum or palladium catalysts to facilitate oxidation, utilize temperatures lower than the direct-fired afterburners. A comparison of temperatures required to convert various combustibles to CO₂ and water for both direct-fired and catalytic afterburners is given in Table 8.

TABLE 8. COMBUSTION TEMPERATURES IN DIRECT-FIRED
AND CATALYTIC AFTERBURNERS (1)

Combustible	Ignition Temperature (°C)	
	Direct-Fired	Catalytic
Methane	632	500
Carbon Monoxide	665	260
Hydrogen	574	121
Propane	480	260
Benzene	580	302

Direct-fired afterburners have exhibited conversion efficiencies of more than 99 percent while catalytic units have slightly lower efficiencies (85 to 92 percent) (2).

Direct-fired afterburners are designed to operate at about 1400°F (760°C) with retention times of at least 0.8 seconds (2). Catalytic afterburners operate at about 1000°F (538°C) with retention times of 0.05 to 0.1 seconds (2). Operating temperatures are sustained by combustion of a fuel gas. This fuel consumption can only be partially offset by heat recovery systems in which heat from exhaust gases is used to preheat incoming gases. Another general disadvantage of afterburners is that they produce no saleable product.

Catalytic afterburners have a number of important advantages and disadvantages compared to direct-fired units. Because they operate at lower temperatures, they have lower operating and maintenance costs. Initial capital equipment cost, however, is higher. Catalysts also are easily poisoned by heavy metals, halogens, and sulfur compounds, or fouled by inorganic particulates. Catalytic incineration devices have been judged by the Los Angeles County Air Pollution Control District to be incapable of meeting efficiency requirements of 90 percent conversion.

Flares incorporate direct combustion of the pollutant gases with air, and can be used only if the organic concentration of the gas stream is in the flammable range. Flaring is the least costly form of incineration since the contaminants emitted are used as the fuel. An auxiliary fuel is usually made available to maintain a flammable mixture in the event the organic concentration drops below the lower explosive limit.

In condensation systems, the gas stream is cooled and compressed to facilitate condensation of vapor phase pollutants. Condensation is applicable when pollutants with dewpoints above 30°C are present in high concentrations. Condensers are normally used in conjunction with other control equipment, since they are a relatively inefficient means of control at lower organic concentrations.

Carbon adsorption systems employ parallel cycling beds of activated carbon to adsorb gaseous organic pollutants. Removal efficiencies are claimed to be up to 95 percent (1). Carbon bed regeneration and desorption of organics is accomplished by a number of means, i.e., steam contacting, hot inert gas contacting, or vacuum desorption. The concentrated organic vapor is either incinerated or recovered as solvent by condensation, distillation, or adsorption.

If pollutant concentration is below 0.1 percent by volume, carbon regeneration is not economical and a non-regenerative system should be utilized, in which spent carbon would be disposed of or regenerated in external equipment. There are a number of important design criteria that must be considered when selecting carbon adsorption systems (1).

The capacity of the solid adsorbent decreases with increasing temperature; therefore operating temperatures should be kept below 40°C for efficient operation. Because the adsorption reaction is exothermic, there is a temperature rise of about 10°C for dilute organic solvent-air mixtures. However, concentrated hydrocarbon streams can cause temperatures to rise to dangerously high levels, presenting an explosion hazard if the gas-air mixture is within explosive limits. Excessive temperature fluctuations must be avoided since periods of temperature rise can cause massive desorption (1).

Operational problems are mainly related to the adsorbent surface. High molecular weight molecules may not be easily desorbed under normal regeneration; high temperature steam stripping may be required to control organic build-up. Particulate matter may adhere to the adsorbent surface and become almost impossible to remove. Plugging may occur from particulate build-up. In some operations it may be necessary to place a filter at the inlet to the adsorber to protect against particulate entry. Corrosion can be a problem if steam stripping is used for adsorbent regeneration. Light hydrocarbons, such as methane and ethane, are not effectively adsorbed and will be present in the off-gas (1).

The major advantages of carbon adsorption systems are that a saleable organic solvent may be recovered through desorption, or the desorbed concentrated gaseous pollutant can be incinerated in a much smaller unit with much less fuel consumption than if the original gas stream were incinerated. Another major advantage of carbon adsorption is that sulfur oxides, nitrogen oxides, and carbon monoxide are concurrently adsorbed with organic vapors; however, no information was found on removal efficiencies.

5.2.4 Sulfur Dioxide Control Technology

There are well over thirty processes that have been developed for the control of SO₂ stack emissions. They can be divided into a number of broad categories, namely dry additive injection (limestone), dry adsorptive processes, wet adsorption processes, adsorption by charcoal, and catalytic conversion processes.

The dry additive injection process involves the introduction of pulverized limestone or dolomite directly into the flue gas. The additive reacts with sulfur dioxide and oxygen in the flue gas to form calcium or magnesium sulfate. Major characteristics of dry additive injection techniques are listed below (1).

- (1) Flyash and limestone particles are carried along in the gas stream and must be removed by another pollution control unit.
- (2) Capital cost is low. Feed materials are relatively inexpensive.
- (3) SO₂ removal efficiencies are low.
- (4) Operational difficulties included sintering and slagging of limestone.
- (5) There is little corrosion and no interference with boiler operation.
- (6) It is a throw-away process and presents solid waste disposal problems.

Dry adsorption processes utilize a bed of metal oxide to adsorb SO₂ from the gas stream. The metal oxide is converted to the sulfated form and must be regenerated. A list of characteristics of dry adsorption techniques is given below:

- (1) Adsorbent generation is difficult and the adsorbents lose their activity after a number of regeneration cycles.
- (2) The most effective adsorbents are very expensive.
- (3) Fly ash and metal oxide particulates must be removed in a second pollution control unit.
- (4) Little corrosion of metal surfaces occurs, and in most cases there is no pressure loss through the system.
- (5) A saleable by-product such as ammonium sulfate can be produced; hydrogen sulfide, which can be routed to the Stretford unit for recovery of sulfur, may be produced.
- (6) Particulate matter may plug absorbent beds.

Wet adsorption processes employ a spray tower or other wet scrubber to carry out SO₂ removal. The adsorbent liquid is usually a water solution of lime, dolomite, metal sulfite, magnesium and manganese oxides, ammonia, or caustic soda. Products from regeneration are concentrated SO₂, ammonium sulfate, or a waste stream. A number of characteristics in the processes are listed below (1):

- (1) Wet adsorption methods are not restricted by temperatures or residence times within the furnace.
- (2) They can be added to existing units without boiler modifications.
- (3) Heat loss due to scrubbing reduces plume buoyancy and the effluent gas stream must be reheated.
- (4) Adsorbents have a capacity for heavy loading but require complex regeneration unless a throw-away system is acceptable.
- (5) Wet adsorption techniques remove particulates and NO_x as well as sulfur oxides.
- (6) Mist eliminators must be included to avoid excess plume opacity.
- (7) Efficiencies in most wet absorption processes are better than 90 percent.

Charcoal adsorption systems utilize commercial activated carbon to chemisorb SO₂ from the gas stream. The SO₂ is oxidized to sulfuric acid in the presence of water vapor, and oxygen. The spent carbon is regenerated thermally. Both dry and wet adsorption technologies are available. Advantages and disadvantages of charcoal adsorption systems are listed below:

- (1) Smaller adsorber-desorber units are required due to the short retention periods.
- (2) Problems with regeneration are inherent including loss of carbon due to CO and CO₂ formation during thermal regeneration.
- (3) Wet processes require added equipment and corrosion resistant construction.
- (4) Due to the continuous movement of the charcoal material in the system, carbon abrasion becomes a problem.

- (5) Wet processes generate a wastewater stream and reduce plume buoyancy.

In catalytic conversion processes, gaseous sulfur dioxide is oxidized to sulfur trioxide in the presence of a vanadium catalyst. The SO_3 reacts with water vapor in the flue gas and is condensed as sulfuric acid. The characteristics of catalytic conversion of SO_2 are discussed below (1):

- (1) It is a simple process with no catalyst recycling required. There is no heat loss and plume buoyancy is maintained.
- (2) Corrosion resistant materials are required.
- (3) A particulate control unit is required to remove fly ash so that reactor plugging does not occur.
- (4) The gas stream must be reheated to a high temperature for efficient conversion (371 to 472°C).
- (5) A mist eliminator or electrostatic precipitator must be added at the end of the process.
- (6) A saleable by-product (H_2SO_4 or NH_4SO_4) is produced.

Because of the large number of sulfur dioxide removal processes, it is not possible to discuss each one separately. A summary of known removal processes is given in Table 9.

5.2.5 NO_x Emission Control

There are two major techniques for nitrogen oxide control, i.e., combustion modification and flue gas treatment. Combustion modification techniques prevent the formation of nitrogen oxides; flue gas treatment techniques provide potential alternate methods to control or reduce the quantity of nitrogen oxides once they are formed. Combustion modification techniques are discussed in Section 5.6. NO_x removal processes are presently available.

TABLE 9. SO_x REMOVAL SYSTEMS (3)

PROCESS	SORBENT	SORPTION PRODUCTS	RAW MATERIAL	REGENERATION PRODUCTS	SPONSORING ORGANIZATIONS
Low Temperature Aqueous Sorption and Regeneration					
Sea water	H ₂ O	H ₂ SO ₃ , sulfites	CaO, Mn ²⁺	CaSO ₄	Battersea, Haenisch-Schroeder, Kanagawa
Sulfacid	H ₂ O, charcoal	H ₂ SO ₃ , H ₂ SO ₄	—	Dilute H ₂ SO ₄	Lurgi, Hitachi
Westvaco	"	"	H ₂ S	S, SO ₂	Westvaco
Thiogen	H ₂ O	H ₂ SO ₃	BaS	S, SO ₄ ²⁻ , S ₂ O ₄ ²⁻	Balakilla smelter
Ozone	H ₂ O, O ₃ , MnSO ₄	H ₂ SO ₄	—	—	TVA
Soda	Na ₂ CO ₃	Na ₂ SO ₃ Na ₂ SO ₄	—	—	UOP, Wisconsin Power, Peabody Coal, Dow Chemical, Nevada Power
Soda ZnO	NaOH, Na ₂ SO ₃	NaHSO ₃	ZnO	ZnSO ₄ , ZnSO ₃ , ZnO, Na ₂ SO ₃ , SO ₂	UOP, Wisconsin Power, Aerojet, Ohio Corp., Peabody & Wellman Powers (Olin Corp.), Johnstone
Soda Sulfite	Na ₂ SO ₃	"	Electrolysis	H ₂ SO ₄	Stone & Webster - Ionics
Potassium sulfite-bisulfite	K ₂ CO ₃ , K ₂ SO ₃	KHSO ₃ , K ₂ S ₂ O ₅	—	SO ₂ , H ₂ SO ₄	Tampa Electric, Wellman-Lord, Ohio-Matheson
Ammonia	NH ₄ OH	(NH ₄) ₂ SO ₃ , NH ₄ HSO ₃ , (NH ₄) ₂ SO ₄	H ₂ SO ₄	SO ₂ , S, (NH ₄) ₂ SO ₄	Simon-Carves, Olin-Matheson, Trail, Kiyoura, Mitsubishi, Showa-Denka, Guggenheim
Ammonia (Guggenheim, Cominco)	NH ₄ OH	NH ₄ HSO ₃	Steam, H ₂ SO ₄ , CaO, Coke, CH ₄	CaSO ₄ , NH ₃ , S	ASARCO, ICI, Trail, Mitsubishi, Showa-Denka, Wade, TVA
Ammonia-zinc oxide	NH ₃	NH ₄	ZnO	SO ₂	U.S. Bureau of Mines (Morgantown)
Ammonia-hydrazine	NH ₃ -N ₂ H ₄	(N ₂ H ₅) ₂ SO ₃ , (N ₂ H ₅) ₂ SO ₄	Steam	SO ₂ , N ₂ H ₄ , (NH ₄) ₂ SO ₄	Aerojet General
Wet lime-limestone	CaCO ₃ , CaO	CaSO ₃ , CaSO ₄	—	—	Bechtel-Still, Howden-ICI, Combustion Engr., TVA, Zurn, Babcock & Wilcox, Peabody, A. B. Balco (Research Cottrell), Battersea, UOP
Basic aluminum sulfate	Al(OH)SO ₄	Al(OSO ₃ H)SO ₄ , Al(OSO ₃ H)SO ₄	CaO, CaCO ₃	CaSO ₄ , SO ₂	ICI, Outokumpu Oy, Boliden
Magnesium oxide and hydroxide (Chemico basic)	MgO, Mg(OH) ₂	Mg(HSO ₃) ₂ , MgSO ₃ , MgSO ₄	NH ₃	(NH ₄) ₂ SO ₄ , H ₂ SO ₄ , MgO, SO ₂	Boston-Edison, Chemical Const. Corp., Babcock & Wilcox, U.S.S.R.
Manganese oxide and magnesium hydroxide	Mg(OH) ₂ , MnO ₂	MgSO ₄ , MnSO ₄ , MnSO ₄ O ₆	Coal	S, H ₂ S, SO ₂ , MnO ₂	Zinkindustrie, Wilhelm Grillo, TVA
Formate	KOOCH	K ₂ S ₂ O ₅	Steam, CO ₂ , CO	H ₂ S, S	Consolidation Coal
Citrate	Sodium citrate	HSO ₃ complex	H ₂ S	S	U.S. Bureau of Mines (Salt Lake City)
Low Temperature Aqueous Sorption and Regeneration					
Sulfidine	Xylydine or tolydine	—	—	SO ₂	Norddeutsche Affinerie
Organic scrubber	Glycol, Amine	—	Steam	SO ₂	Arthur D. Little
Medium Temperature Liquid or Solid Sorption and Regeneration					
DMA(bromestone)	Dimethyl aniline	SO ₂	Reformed CH ₄	S	ASARCO - Phelps Dodge
Reinluft	Activated charcoal	SO ₃	Steam	SO ₂ , H ₂ SO ₄	Commonwealth Assoc., Reinluft, Hitachi, Bergbau, Torschung
Boliden	Coke	—	—	S	Boliden, ICI, Trail, Cominco, Billingham
Catalytic oxidation	V ₂ O ₅ or NO ₂ catalysts	SO ₃	NH ₃	SO ₃ , H ₂ SO ₄ , (NH ₄) ₂ SO ₄	Metropolitan Edison, Monsanto-Penelec, Tyco, Kiyoura, SNPA-Topoe, ill. Power
Alkalized alumina	N ₂ O, Al ₂ O ₃	Na ₂ SO ₄ , Al ₂ SO ₄	Reformed CH ₄	S, H ₂ S	CEGB, U.S. Bureau of Mines (Bruceton)
Alkali	Nahcolite	—	—	SO ₄ ²⁻	Precipitator Pollution Control
Alkaline-earth	CaO, MgO	MgSO ₄	CO	C, CaSO ₄ , MgSO ₄	Battelle, Combustion Engr., Wikerl, CRIEPI, TVA, Steinkohlen Elektrizität
Lignite ash	CaO	CaSO ₃	—	SO ₂ , CaO	Carl Still
MnO ₂ (DAP)	MnO ₂ , ZnO	MnSO ₄ , ZnSO ₄	NH ₄ OH	(NH ₄) ₂ SO ₄ , SO ₂ , MnO ₂	Mitsubishi, Aerojet
CuO	Cu + Al oxides	CuSO ₄	CH ₄ , H ₂	S	UOP, Exxon, Shell, U.S. Bureau of Mines (Bruceton)
Liquid SO ₂	Liquidification	SO ₂	—	—	Tacoma, Canadian Ind. Ltd., Copper Cliff Spanish Smelter
Molten carbonate	Carbonates of Li, Na, K	SO ₄ ²⁻ and SO ₃ ²⁻ of Li, Na, K	C + H ₂ O, CO + H ₂	H ₂ S	Atomics International, Consolidated Edison, Garrett, North American Rockwell
Liquid claus	—	—	H ₂ S	S	Institut Francis du Petrole, Nippon, UOP
Solid claus	—	—	Al ₂ O ₃ , H ₂ S	S	Princeton Chemical Research
Transition metal on alumina	—	—	Oxides, CO	S	Chevron Research, U.S. Bureau of Mines (Twin Cities)
Flyash	—	—	Flyash, CH ₄	S	GATX
Low temperature reduction	—	—	Oxides, CH ₄ , CO, H ₂	S	Allied Chemical, Texas Gulf Sulfur
Direct reduction	—	—	Oxides, CH ₄ , C	S	Outokumpu Oy

Source: Information Circular 8698, U.S. Dept. of the Interior, Wash. DC.

Potential techniques for NO_x treatment are categorized as follows:

- (1) Catalytic decomposition
- (2) Catalytic reduction
- (3) Adsorption by solids
- (4) Absorption by liquids

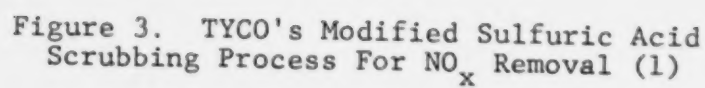
Catalytic decomposition processes would convert nitrogen oxides to nitrogen and oxygen gas. At present no commercially available catalysts have been found which would be sufficiently active at reasonably low temperatures. Indications are that if and when the catalyst is found, it may have to be used at temperatures above 1000°F (538°C) (1).

In catalytic reduction processes, a reducing agent would react with nitrogen oxides to form elemental nitrogen and an oxidized compound. Ammonia is known to be capable of reducing NO_x selectively in an oxygen-containing atmosphere. If found effective, the technique might also simultaneously control sulfur oxide emissions. The reduction reaction requires temperature control and a catalyst, which presently is not available (1).

Both activated carbon and silica gel have been found to adsorb nitrogen oxides to a considerable degree; activated carbon has demonstrated better performance. Other potential solid adsorbents are metal oxides, particularly manganese and alkalized ferric oxides. Severe attrition of the sorbent is a major technological problem yet to be solved (1).

Absorption of nitrogen oxides by alkaline solutions seems to be the most promising control technique. For this method, equimolar concentrations of NO and NO_2 are essential in the flue gas. The most feasible possibility for equimolar control is the recycle of NO_2 formed during absorbent regeneration. A number of liquid absorbent processes are in the pilot plant stage. None are commercially available at present (1).

The TYCO process, as shown in Figure 3, produces both nitric and sulfuric acids from oxides of sulfur and nitrogen in the flue gas. The process requires the recycle of NO_2 to oxidize SO_2 to sulfuric acid. The NO_2 is oxidized to form N_2O_3 . A high efficiency scrubber would be required for N_2O_3 .



The lime scrubbing process would be similar to the process discussed under sulfur oxide controls. Oxides of nitrogen and sulfur are simultaneously absorbed by a lime slurry in a spray tower. The calcium nitrite formed is decomposed and NO is oxidized to NO₂ which is recycled to the flue gas to control equimolarity between NO and NO₂. Nitric acid and gypsum are formed as by-products, as shown in Figure 4 (1).

Magnesium hydroxide can also be used simultaneously to adsorb oxides of nitrogen and sulfur. Magnesium sulfite is removed in a settling tank while the overflow, containing magnesium nitrite, is evaporated and decomposed. NO is formed in the decomposition reaction. It is oxidized to NO₂ and recycled to the flue gas for equimolar control. The magnesium sulfite is decomposed to MgO and SO₂. Process by-products are sulfuric acid and ammonium nitrite. The process is shown in Figure 5 (1).

The urea scrubbing process involves the reaction of nitrogen oxides with an acidic urea solution to form nitrous acid solution. The nitrous acid reacts with urea to form nitrogen, water, and carbon dioxide. This technique has been proven on the pilot scale. Cost of urea is the major operating expense. No saleable products are recovered in the process, which is shown in Figure 6 (1).

Removal efficiencies for any of the NO₂ control technologies were not available.

5.2.6 Control Module Selection

There are seven major gaseous waste streams which must undergo treatment to remove one or more specific pollutants. Table 10 lists the seven gas streams and the contaminants that might have to be removed. Characteristics of the gas streams which may prove important in equipment selection are also provided. Regulations with respect to emissions of specific pollutants have been discussed in Chapter 4.0.

Dust streams from coal storage, receiving, reclaiming, and crushing and from sulfur and SRC storage will generally possess highly variable flow rates and grain loadings. Particle sizes are frequently in the 1 to 10 micron range and highly efficient particulate removal equipment must be employed. For relatively small storage piles, such as sulfur storage, enclosures with particulate control apparatus must be compared to outside storage piles using organic

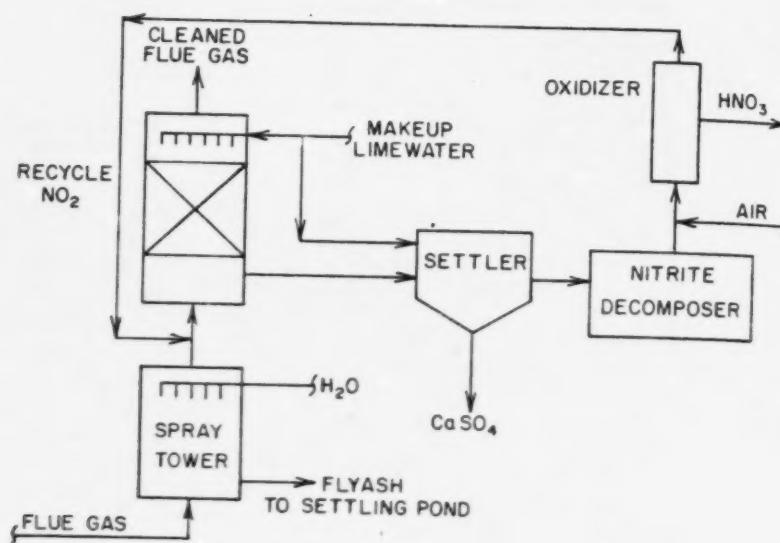


Figure 4. Lime Scrubbing For NO_x Removal (1)

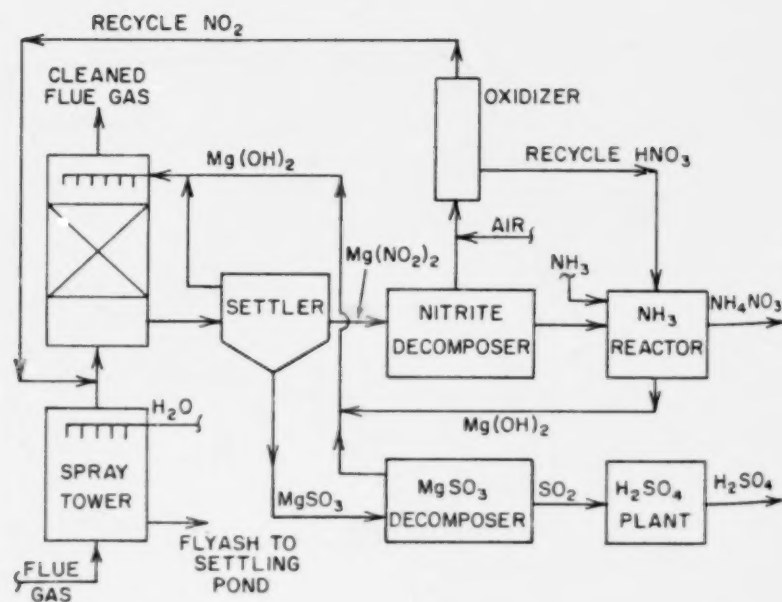


Figure 5. Magnesium Hydroxide Scrubbing
Of NO_x (1)

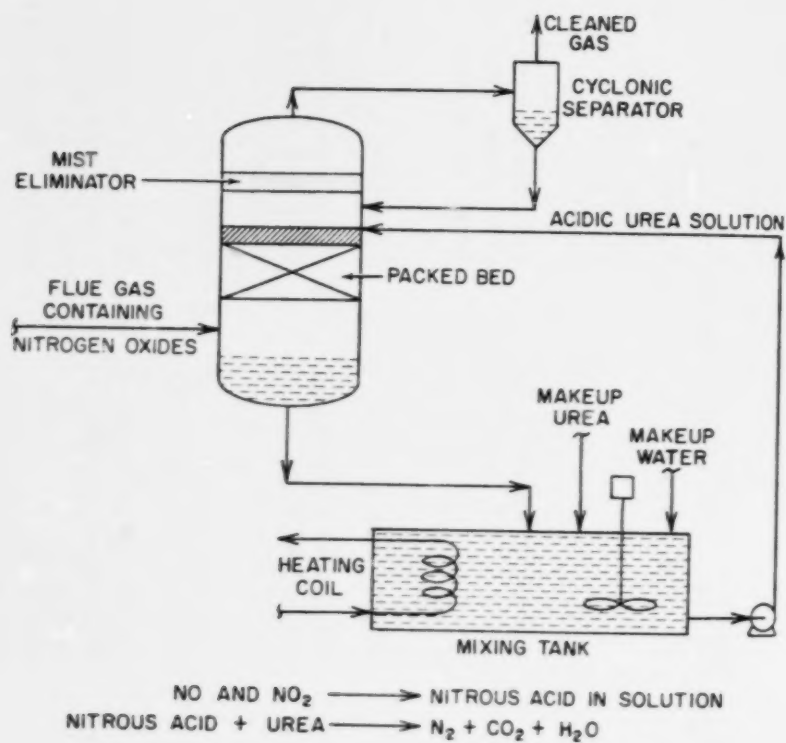


Figure 6. Urea Scrubbing Process
For NO_x Removal (1)

TABLE 10. GASEOUS WASTE STREAMS IN THE SRC PROCESS -
MAJOR CONTAMINANTS AND STREAM CHARACTERISTICS

Stream	Major Pollutants	Stream Characteristics and Criteria for Control Module Selection
1. Dust from coal receiving	Particulates	Highly variable; ambient temperature and pressure; high grain loading; abrasive; particle size 1-100 μ .
2. Dust from coal storage	Particulates	Intermittent; dispersed; variable dependant on wind conditions; same as above.
3. Dust from coal reclaiming and crushing	Particulates	Same as 1.
4. Stack gas from coal drying	Volatile organics Particulates Moisture	High temperature, pressure and flow rate; low grain loading; high moisture content.
5. Dust from SRC product storage	Particulates Volatile organics	Same as 1.
6. Effluent gas from Stretford sulfur recovery	Light hydrocarbons Nitrogen oxides Ammonia Fly-ash Hydrogen sulfide	Moderate temperature and pressure; low grain loading; high flow rate; corrosive low pollutant concentrations; relatively constant.
7. Flue gas from coal-fired boilers (Steam Generation)	Sulfur dioxide Nitrogen oxides Particulates Carbon dioxide	High temperature; near atmospheric pressure; high flow rate; corrosive; abrasive; moderate grain loading, relatively constant.

polymer coatings for dust control. For larger coal piles, such as the ROM pile, enclosure is infeasible. Dusts from receiving, reclaiming and crushing operations can be controlled by a number of means.

Generally, electrostatic precipitators are only economically feasible for the treatment of relatively large gaseous streams at high temperatures. Efficiencies of removal are dependent on flow rate. Since dust streams are relatively small and possess variable flow rates, electrostatic precipitators were not chosen as a viable means of control.

Wet scrubbing techniques for particulate removal were also not chosen as a viable alternative because of excessive water use and the generation of an additional wastewater stream.

Baghouses and cyclones were chosen as the most viable means of particulate control in dust generating operations. Two alternate systems are available. In some operations, a single baghouse (or fabric filter) may be adequate to control dusts. In other applications a cyclone may be needed prior to baghouse, in order to provide adequate and economical particulate removal. In Chapter 6.0, the two systems will be discussed with respect to their application and costs for specific gaseous waste streams in the SRC process.

The most feasible methods for controlling hydrocarbon emissions from sulfur recovery unit tail gas are incineration and carbon adsorption. Incineration has the advantage of oxidizing other pollutants (H_2S , NH_3 , CO) as well as the hydrocarbon component. Carbon adsorption may not be well suited to remove the light hydrocarbon streams expected in the tail gas.

Since sulfur dioxide emissions are expected to be significant, wet scrubbing processes have been suggested for boiler flue gas treatment. Their ability to simultaneously remove particulates, sulfur dioxide, and nitrogen oxides from flue gas gives them a definite advantage over electrostatic precipitators, which are more cost effective only when sulfur and nitrogen oxide levels are low.

5.3 Liquid Treatment

5.3.1 Introduction

This section deals with the selection of wastewater pollution control equipment which may be applicable to the treatment of coal liquefaction wastewaters containing suspended solids, dissolved solids, extreme pH, hardness, toxic chemical species, oil wastes, and oxygen demanding species. The various treatment technologies discussed provide viable alternatives that might be considered for rendering wastes acceptable for either discharge or for recycle/reuse within the plant. Although this discussion does not encompass every treatment alternative that might be considered, a representative survey of the most significant treatment processes has been included.

5.3.2 Pollution Control Equipment

Selection and sizing of pollution control equipment for the SRC process depends on flow rate, variability of flow, amenability of wastewaters to chemical and/or biological treatment, chemical composition, chemical recoverability, intended end-use of treated wastewaters (i.e., discharge to stream or recycle to plant), and economic considerations. Parameters generally considered in the design of pollution control equipment are BOD, COD, temperature, pH, suspended solids, dissolved solids, heavy metals, toxic materials such as cyanides and phenols, and oils and grease.

Highly variable and polluted wastewaters usually need one or more pretreatment processes such as equalization, neutralization, solids removal, heavy metals removal, oil and grease removal, toxic pollutant removal (i.e., phenols and cyanides), and chemical recovery operations. These methods provide preliminary removal of excess quantities of wastewater stream constituents and prevent various stream parameters from adversely affecting the operation of the main treatment processes. Depending on the removal efficiencies of the main treatment processes, additional wastewater treatment may also be required to reduce the wastewater constituents to acceptable levels.

Pollution control processes may be divided into three classes according to their treatment function, i.e., primary, secondary or tertiary treatment. Table 11 lists the general classes of treatment methods and applicable processes within each class which may be employed in a coal liquefaction plant.

TABLE 11. TREATMENT PROCESSES

<u>Class of Treatment</u>		
<u>Primary</u>	<u>Secondary</u>	<u>Tertiary</u>
Equalization	Biological	Filtration
Sedimentation	Flocculation/Flotation	Carbon Adsorption
Neutralization		Advanced:
Oil and Grease Separation		Electrodialysis
		Reverse Osmosis
		Ion Exchange
Recovery Processes		
Ammonia		
Phenol		
Sulfur		
Stripping		

In the selection of pollution control equipment, the most significant pollutants to be removed from each wastewater stream must first be determined. Then it must be decided whether to segregate or integrate various wastewater streams prior to treatment. Also, it must be decided if any stream constituents may be recovered. Once the chemicals to be recovered and main treatment systems needed to treat various wastewater streams have been identified, then the appropriate pretreatment (primary) and post treatment (tertiary) methods may be selected.

The following sections deal with the various treatment operations included under the three classes of treatment.

5.3.2.1 Primary Treatment

Primary treatment units are designed to remove wastewater stream constituents which may adversely affect the operation of the main treatment processes and/or may be recovered economically. Applicable primary treatment operations are enumerated in Table 11.

5.3.2.1.1 Recovery Operations

In the SRC process, there are a number of pollutants, namely, sulfur, ammonia, and phenols, which may be recovered economically from the wastewater streams. Although they have been included in the auxiliary process modules, they are, in essence, primary (pretreatment) treatment processes. If it had not been economically feasible to recover these compounds, then it most likely would have been necessary to incorporate various treatment methods into the overall treatment process to remove them or render them harmless.

5.3.2.1.2 Primary Solids Removal

Sedimentation is a solids-liquid separation process whereby suspended solids are separated from water and concentrated by gravity settling. This type of separation is effective when the suspended solids are capable of settling readily as is the case for domestic wastewaters. Often, wastewaters may contain finely divided suspended matter which does not settle easily. Chemical coagulants are usually added in these instances to agglomerate the suspended matter into larger particles which exhibit improved settling characteristics. Typical coagulants are alum, ferric chloride, and aluminate. Popular coagulant aids are bentonite, powdered carbon, activated alumina, and polyelectrolytes.

Sedimentation removal efficiencies vary widely depending on the nature of the influent suspended matter. A well designed and operated tank should remove between 50-60 percent of the influent solids (4).

Sedimentation tanks may be either rectangular or circular. The detention times in circular tanks is usually between 90-150 minutes with surface loading not to exceed 600 gpd/ft² (36.7 m³/day/m²) (4).

The design of rectangular sedimentation tanks is usually based on the wastewater flow, solids loading, and settling characteristics. The horizontal velocity through the chamber is given by the following equation (4):

$$V = V_s \frac{L}{d}$$

where* V = maximum horizontal velocity (ft/sec)

V_s = terminal settling velocity of the particle to be removed (ft/sec).

L = length of basin (ft)

d = depth of basin (ft)

The terminal settling velocity in ft/sec may be estimated from the following equation (4):

$$V_s = \frac{(\rho_s - \rho_l) g D^2}{18 \mu}$$

where*

ρ_s = density of solid particle (lb/ft³)

ρ_l = density of wastewater (lb/ft³)

D = diameter of solid particle (ft)

μ = viscosity of wastewater (lb/sec-ft)

g = acceleration of gravity (32.2 ft/sec²)

*Metric conversion factors are given in Appendix A.

Horizontal velocities are usually less than or equal to 1.0 fps (0.3 m/s) (4). This fixes the size of the chamber for a given flow rate.

Tube settlers may also be used to remove suspended matter in lieu of sedimentation basins. They essentially act as a series of rectangular basins, where water enters the

bottom of the inclined tube settler and flows upward through the tubes. Particles tend to move toward each tube wall where they become entrapped in a layer of particles previously settled. The steep incline of the tubes causes the sludge to counterflow along the side of the tubes after it accumulates. It then falls into a sediment storage sump below the tubes assembly. The inclined tube settler configuration also requires influent and effluent chambers to distribute the flow to the tubes and to collect it after clarification.

Inclined tube settlers are manufactured with tubes having various geometrically-shaped cross sections. Systems employing flocculation with inclined tube settlers are capable of removing particles less than 10 microns in diameter (fine sand). They are usually used to clarify influent waters which have under 1000 mg/l of suspended solids (5). The number of tubes may be increased to provide treatment for virtually any flow rate desired.

The horizontal velocity through the settler is given by the following equation (5):

$$V = \frac{V_s L \cos A}{d}$$

where: $A = \text{angle of inclination } (0.0 \leq A \leq \tan^{-1} \frac{L}{d})$

Tube settlers are generally designed for flows of 5-8 gpm/ft² (3.4×10^{-3} to 5.4×10^{-3} m³/s/m²) (6).

In addition to sedimentation basins, screening devices may also be used to remove suspended solids. Separator screens normally consist of rectangular or circular structures supporting wire mesh screens. Water is introduced directly onto the screen surface. Solids are detained on the surface while the screened water exits downward. Trapped solids are vibrated to the outer periphery of the screen element for disposal. Typical separator screens may remove particles ranging from a few hundred microns in diameter to as small as 45-50 microns (5). Screen designs are based on the screen opening and solids loadings which can be accommodated without blinding the screen. The sedimentation removal rate decreases with decreasing size of particles removed.

5.3.2.1.3

Steam Stripping

Steam stripping may be used to remove hydrogen sulfide, ammonia, and phenol from a wastewater stream. Depending on the operating temperature and pressure, the ammonia and hydrogen sulfide content of the raw feed, the type of system - refluxed or nonrefluxed and the number and efficiency of trays or packing, approximately 98-99 percent of the hydrogen sulfide and 95-97 percent of the ammonia present in the raw feed stream may be removed (7). It has also been observed that up to 40 percent of any phenols present in the raw feed may also be removed by this process (7).

The volume of steam required in this process has been found to vary between 0.9-1.1 (0.4-0.5 kg) pounds of steam per gallon of tower feed (7). As high as 2.0 (0.9 kg) pounds per gallon have been used. Typical design parameters include 8-10 trays, a tower pressure of 5-30 psig (3.4×10^4 to 2.1×10^5 Pa), and a tower temperature of 230-270°F (110-132°C) (7). The stripper volume will depend on the composition of the feed stream and the number of trays required to produce the desired effluent.

This system has an advantage over air stripping systems in that chemical addition is not required and additional compounds can be removed.

5.3.2.1.4

Equalization

Equalization is a process whereby the composition of a wastewater stream is made uniform and the volumetric flow rate constant. It is normally required when a number of streams with highly variable chemical compositions and flow rates are combined for treatment. The addition of equalization facilities to a treatment plant improves the efficiency, reliability, and control of subsequent physical, chemical and/or biological treatment processes.

Equalization basins are normally designed with a preset detention period for chemical mixing (i.e., 15-30 minutes) based on the average daily flow, or, in the case of highly variable flows, to retain a sufficient portion of the wastewater stream, while maintaining adequate freeboard, in order that a predetermined constant flow rate is discharged to the treatment plant (8).

5.3.2.1.5 Neutralization

When biological treatment processes are used to treat industrial wastes, the influent wastewater stream pH should be between 5.0 and 10.0. Extreme pH wastewaters may be adjusted within these units by the addition of acids or bases. Common reagents used for neutralization are summarized in Table 12.

TABLE 12. NEUTRALIZATION REAGENTS

Acid Wastes	Alkaline Wastes
Waste alkalis	Waste acids
Limestone	Sulfuric acid
Lime slurry	Hydrochloric acid
Soda ash	Sulfur dioxide
Caustic soda	
Ammonia	

Selection of neutralization reagents is based primarily on cost considerations. Reagent solubility, neutralization reaction rate, neutralization end products, and ease of operation also require consideration.

The process flow scheme used for neutralization depends on the neutralization reagent(s) employed, desired degree of neutralization and waste flow characteristics. Depending on the rate of waste flow, either continuous or batch-wise neutralization is employed. Generally continuous neutralization is used when the waste flow exceeds 70 gpm ($4.4 \times 10^{-2} \text{ m}^3/\text{S}$). Detention times of 10-30 minutes are typical (6).

5.3.2.1.6

Oil and Grease Separators

Oily wastes may be grouped in the following classifications:

1. Light Hydrocarbons - These include light fuels such as gasoline, kerosene, and jet fuel, and miscellaneous solvents used for industrial processing, degreasing, or cleaning purposes. The presence of these light hydrocarbons may encumber the removal of other heavier oily wastes.
2. Heavy Hydrocarbons (Fuels and Tars) - These include the crude oils, diesel oils, #6 fuel oil, residual oils, slop oils, and in some cases, asphalt and road tar.
3. Lubricants and Cutting Fluids - These are generally in two classes, non-emulsifiable oils such as lubricating oils and greases, and emulsifiable oils such as water soluble oils, rolling oils, cutting oils, and drawing compounds. Emulsifiable oils may contain fat, soap or various other additives.

These compounds can settle or float and may exist as solids or liquids, depending upon such factors as method of use, production process, and temperature of wastewater.

Primary oil-water separators are designed to remove free oils readily separated from a wastewater stream. This process provides a reduction in the oxygen demand of the wastes (both BOD and COD) and reduces operational difficulties caused by oils and grease in subsequent biological treatment processes.

Gravity separators are most commonly used to remove free oils from wastewaters. The difference in densities of oil or grease and water will cause free oily wastes to rise to the surface of the wastewater, where they are collected and removed by skimming devices.

The parameters considered in the design of oil-water separators are: (1) rate of rise of oil globule, (2) minimum horizontal area, (3) minimum vertical cross-sectional area, and (4) minimum depth to width ratio. Design equations are given in Table 13.

The horizontal and vertical areas and the depth to width ratio fix the size of basin to be used.

TABLE 13. GRAVITY OIL-WATER SEPARATOR
DESIGN EQUATIONS (6)

(1)	$V_t = 0.0241 \frac{(S_w - S_o)}{\mu}$
(2)	$A_h = F Q_m / V_t$
(3)	$A_c = Q_m / V_h$
(4)	$d/B = 0.3$

where* V_t = rate of rise of a 0.015 cm diameter globule,
(ft/min).

S_w = specific gravity of wastewater at design temperature

S_o = specific gravity of oil in wastewater at design temperature.

μ = absolute viscosity of wastewater at design temperature (poises).

A_h = minimum horizontal area (ft²)

Q_m = wastewater flow (ft³/min)

F = correction factor for turbulence and short circulating in separator (see Figure 7).

A_c = minimum vertical cross-sectional area (ft²)

V_h = horizontal flow velocity (fpm), not to exceed 3 fpm

d = depth of wastewater in separation (ft)

B = width of separator channel (ft).

*Metric conversion factors are given in Appendix A.

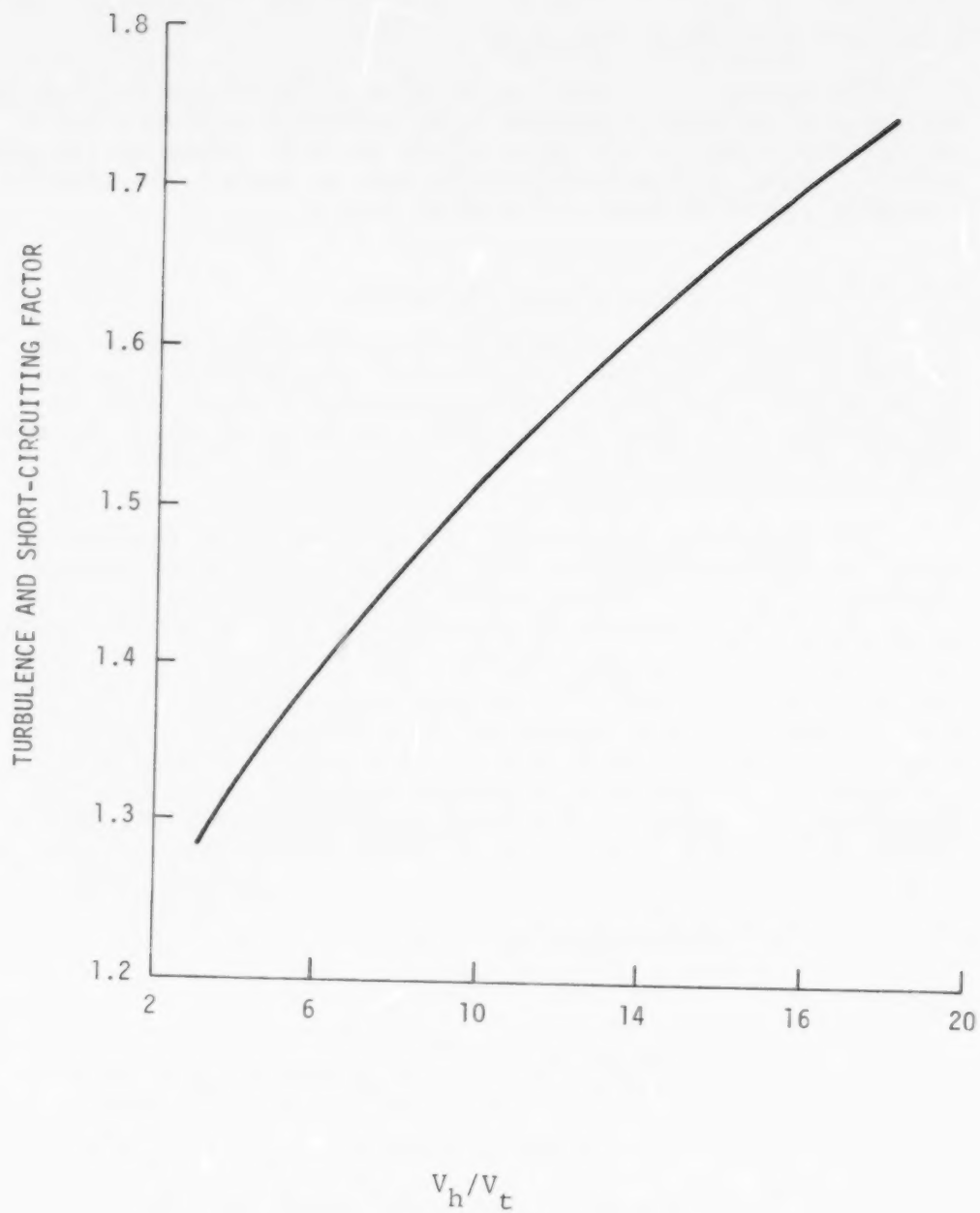


Figure 7. Recommended Values of F for Various Values of V_h/V_t (6)

5.3.2.2 Secondary Treatment

Biological treatment and flocculation/flotation are the two main treatment processes most commonly employed for wastewaters similar to those found in coal liquefaction processes. When flocculation/flotation is needed, it usually precedes the biological treatment system.

5.3.2.2.1 Flocculation/Flotation

Air flotation is a process whereby suspended matter, including both suspended solids and insoluble oily wastes, is separated from water. This process is often used in conjunction with gravity oil/water separators when there are significant quantities of both free and emulsified oils present in wastewaters.

Air flotation separates oil globules from the wastewater by introducing tiny air bubbles into the flotation chamber. The air bubbles attach themselves onto oil globules dispersed throughout the water. The resultant buoyancy of the oil globule - air bubble complex causes it to rise to the water's surface where it is removed by surface skimming devices. Air flotation processes are classified as dispersed air or dissolved air depending upon the method of air introduced into the flotation unit. Pressure dissolved air flotation units are most commonly employed in industrial wastewater treatment. The basic equation governing the separation of oil from water is given below (6):

$$V_t = \frac{g D^2 (\rho_o - \rho_w)}{18 \mu}$$

Where*

V_t = terminal velocity attained by suspended solids passing through water (ft/sec)

g = acceleration of gravity (32.2 ft/sec²)

D = diameter of suspended impurity (ft)

ρ_o = density of oil in waste (lb/ft³)

ρ_w = density of wastewater (lb/ft³)

μ = viscosity of wastewater (lb/sec-ft)

*Metric conversion factors are given in Appendix A.

Based on this principle, the following design criteria have been recommended for rectangular flotation chambers (6):

- The ratio of depth to width should be between 0.3 to 0.5 (depth usually 1.0-2.7 m).
- The maximum ratio of the horizontal water velocity to particle rise velocity is recommended to be 15.
- The maximum horizontal water velocity is recommended to be 1.5 cm/S.
- The optimum length to width ratio is set at 4 to 1.
- A maximum width of 6.7 m is recommended.

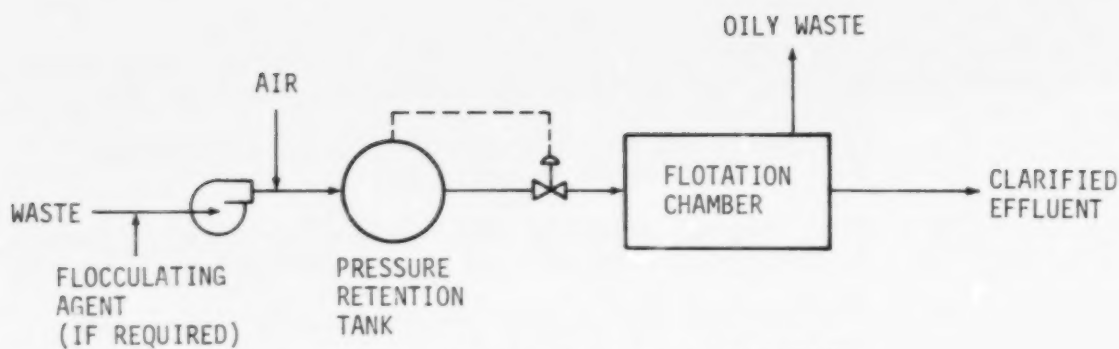
Typical operating parameters are given in Table 14.

TABLE 14. AIR FLOTATION UNIT
OPERATING CONDITIONS (6)

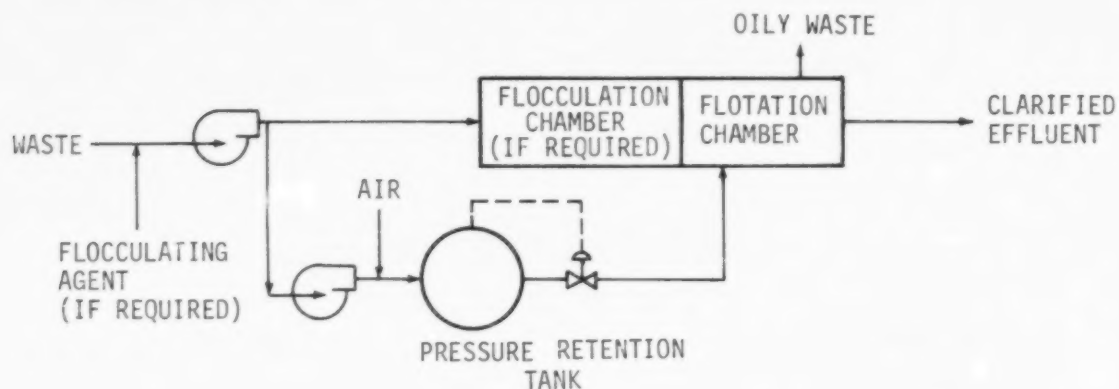
Parameter	Value*
Residence time in flotation chamber	10-40 minutes
Residence time in pressurization tank	1-2 minutes
Hydraulic loading in flotation chamber	1-6 gpm/ft ²
Oily waste loading	2-4 lb/hr - ft ²
Air requirement (full flow operation)	0.35 scf/100 gal.

*Metric conversion factors are given in Appendix A.

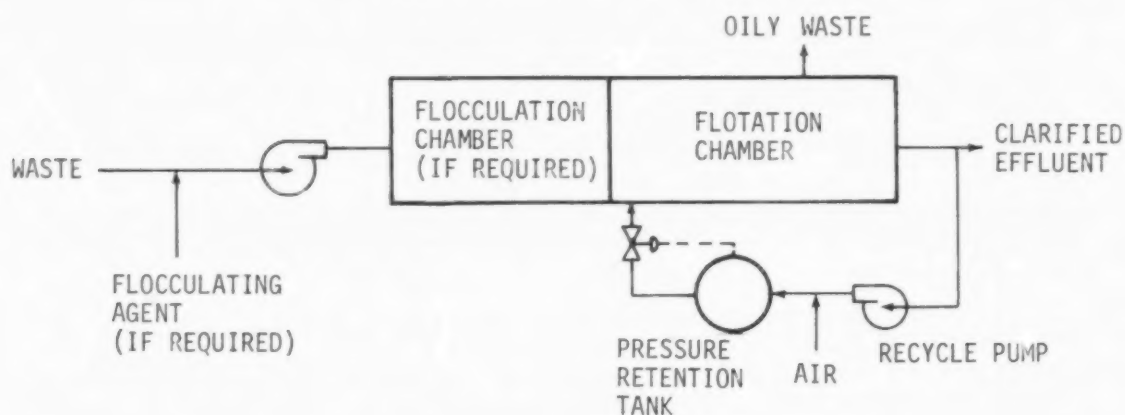
There are three basic flow schemes employed for the pressure type dissolved air flotation process. They are designated as full-flow operation, split-flow operation, and recycle operation. Full-flow operation is the most general form of the process. Split-flow operation is used primarily to remove oily wastes from wastewaters of low suspended solids concentration, while the recycle operation is used when a delicate floc is present in the influent wastewater stream. These operations are shown in Figure 8 (6).



AIR FLOTATION PROCESS: FULL-FLOW OPERATION



AIR FLOTATION PROCESS: SPLIT-FLOW OPERATION



AIR FLOTATION PROCESS: RECYCLE OPERATION

Figure 8. Three Flow Schemes Employed in the Dissolved Air Flotation Process

The efficiency of the air flotation process is dependent upon the influent water characteristics. Water containing free oil is readily removed by this process, while emulsified oil is not. Pretreatment methods, encompassing chemical addition, usually precede the flotation chamber when the influent wastewater contains significant concentrations of emulsified oils. Coagulation/flocculation and acidification are the most common pretreatment methods used. Dissolved air flotation treatment efficiencies are given in Table 15.

TABLE 15. DISSOLVED AIR FLOTATION (6)

Treatment Description	Oil Removal, Percent	
	Floating or Free Oil	Emulsified Oil
Flotation without chemical pretreatment	70-95	10-40
Flotation with chemical pretreatment	75-95	50-90

5.3.2.2.2 Biological Treatment

The three basic types of biological treatment systems applicable to coal liquefaction wastewaters are activated sludge processes, aerated lagoons (oxidation ponds), and trickling filters.

Important parameters to be considered in the design of biological treatment processes are:

- BOD loading
- Oxygen availability
- Temperature
- pH
- Toxicity
- Dissolved salts

Design parameters for various biological treatment systems are given in Table 16.

TABLE 16. BIOLOGICAL TREATMENT SYSTEMS (4)

<u>Process</u>	<u>Loading</u> (lb BOD/day/1000 ft ³)	<u>Detention Time</u> (hours)	<u>Treatment Efficiency</u> (percent)
<u>Activated Sludge</u>			
Extended Aeration	10-25	18-36	75-95
High Rate Aeration	100-1000	0.5-2	75-90
Conventional	20-40	4-8	85-95
Aerated Lagoon	N/A	72-240	80-95
Stabilization Ponds	20-50 ^a	240-720	80-95
<u>Trickling Filters</u>			
Standard Rate	9-14		85
High Rate	69 ⁺		65-75

^aunits in lb/acre-day

N/A = Not Applicable

* Only English units are included due to space limitation. Metric conversion factors are given in the Appendix.

The treatment process required for any industrial wastewater will mainly depend on the biodegradability of the waste, cost considerations taking into account other unit processes which may be required, and the degree of treatment required. For example, wastes which degrade very slowly will require longer detention times than wastes which degrade rapidly. This would most likely necessitate the use of lagoon systems in lieu of conventional systems.

In addition to the basic biological treatment unit, secondary clarifiers are also integral components of the biological treatment system. The clarifiers serve two functions: to settle out suspended matter from the biological aeration basin effluent and to recycle a portion of the solids to the aeration basin.

The secondary clarifiers are normally designed for 4-6 hours detention based on the average daily flow (4). Surface loading rates and weir loading rates do not normally exceed 600 gpd/ft² and 10,000 gpd/ft (36.7 m³/day/m² and 126 m³/day/m), respectively (4). The recycle volume from the clarifier to the aeration basin usually ranges from 30-100 percent of the influent flow (4). In the case of trickling filters, there is no recirculation of solids to the filter in standard rate filter systems. In high rate filters, however, the recycle ranges from 100-400 percent of the influent flow (4).

5.3.2.3 Tertiary Treatment

Tertiary treatment basically consists of physical-chemical processes which polish or refine the effluents from secondary processes to within acceptable limits either for discharge to surface water or for plant reuse. Some tertiary treatment processes are filtration, carbon adsorption, ion exchange, electrodialysis, and reverse osmosis.

5.3.2.3.1 Filtration

There are numerous filtration processes which may be used to polish secondary effluent wastewaters. Filtration processes applicable to coal liquefaction wastewaters are given in Table 17 along with design parameters. Filtration processes may be divided into two classes: deep bed filtration and polishing filtration. Microscreening and vacuum filtration are considered polishing filtration while gravity and pressure filters are considered deep bed filtration.

TABLE 17. FILTRATION PROCESSES

Process	Filter Media	Loading ² (gpm/ft ²)	Solids Removal Capacity (lb/unit area)	Efficiency (SS removal)
Microscreening	Garnet	2-10	--	45-85% (5 mg/l)
Gravity Filters				
Downflow	Coal Sand Garnet	2-6	0.3-0.5 (one layer) .5-1.0 (multi-layer)	50-90% 80-90%
Upflow	Coal Sand Garnet	2-6	.5-1.0	50-90%
Pressure Filters	Coal Sand	2-10	0.3-0.5	90%
Vacuum Filtration	Diatomaceous Earth	0.5-1	--	98%

* Only English units are provided due to space limitations. Metric conversion factors are given in the Appendix.

There are three types of deep bed filtration systems which will be described: gravity downflow, gravity upflow, and pressure filters.

Deep bed filtration utilizes a bed of granular filter media to separate suspended matter from water. These systems are usually applicable up to 1,000 mg/l of solids with particle sizes ranging from 0.1 to 50 μ (10). Since the entire filter media is available to capture solids, a clear filtrate is produced.

Downflow filtration involves the filtration of water in a downward direction through progressively coarser filter media. Upflow filtration involves the filtration of water in an upward direction through progressively finer filter media. Prevention of the movement of the filter materials is accomplished by the use of restrictive screens and grids. Polyelectrolytes can be added to the sediment-laden influent for further solids removal by these filters. Pressure filters rely on pumps to force sediment-laden wastewaters either upward or downward through a filter media.

The loading rates are essentially the same for both gravity downflow and upflow filters. The use of upflow filter is generally more advantageous because the filter runs are usually longer and consequently the number of backwashings required are reduced. The use of downflow filters is somewhat disadvantageous because sufficient hydraulic head must be available for successful operation of the filter. A disadvantage of the upflow filter is loss of filter material during the normal operating cycle.

Pressure filters are basically more advantageous than gravity filters for wastewater applications because they can handle higher solids loadings and higher pressure heads and are more compact and less costly. A major disadvantage is the difficulty encountered in servicing the filters when they malfunction. The filter is completely enclosed.

Those parameters which must be considered in the design of deep bed filters are available head loss, filtration rate, influent characteristics, media characteristics, and filter cleaning system. Media characteristics have been found to be the most important considerations in the design of deep bed filters. Media particle size determines the performance and operation of the filter. It has been observed

to be inversely proportional to both filtrate quality and pressure drop across the filter. A distribution of particle sizes (multi-media beds) enables the filter to be utilized more efficiently in that it will not clog as readily as a filter containing only one filter medium. Multi-media filters consequently require less frequent backwashing.

Polishing filters such as the diatomaceous earth vacuum filter are capable of removing suspended solids in the micron and submicron range from very dilute aqueous suspensions. Although they are capable of producing a high quality effluent, the occurrence of varying quantities of influent suspended solids has led to erratic operation of this filter in tertiary treatment operations. A microscreen consists of a rotating drum with a fine screen around its periphery. Feed water enters the drum through an open end and passes radially outward through the screen, depositing solids on the inner surface of the screen. At the top of the drum, pressure jets of effluent water are directed onto the screen to remove the deposited solids. A portion of the backwash water penetrates the screen and dislodges solids, which are captured in a waste hopper and removed through the hollow axle of the unit. Particles as small as 20-40 microns may be removed by this system. Disadvantages include incomplete solids removal and inability to handle solids fluctuations.

5.3.2.3.2 Carbon Adsorption

Carbon adsorption is usually employed as a tertiary treatment unit for the removal of soluble organic matter in wastewaters. Approximately 70-90 percent of the influent BOD and 60-75 percent of the influent COD may be removed by this process when it is preceded by secondary biological treatment (11).

Carbon adsorption design considerations include adsorptive capacity of the carbon, wastewater flow and characteristics and method of carbon contacting. The general range of hydraulic flow rates are 2-10 gpm/ft² (1.4×10^{-3} to 6.8×10^{-3} m³/S/m²) (11). Bed depths are typically 10-30 feet (3.3-10 m) (11). The maximum area for good flow distribution is 1000 ft² (93 m²) (11).

The alternatives for carbon contacting systems include: downflow or upflow contacting, series or parallel operation, pressure or gravity downflow contactors, and packed or expanded bed upflow contactors. Upflow beds have an advantage over downflow beds in that there is a minimum usage of carbon. Upflow expanded beds are able to treat wastewaters relatively high in suspended solids and can employ finer carbon (reduces contact time) without excessive headloss. A disadvantage of the upflow packed bed is that it requires a high clarity influent. The principal use of the downflow contactor is to adsorb organics and filter suspended materials. Pressure downflow contactors increase the flexibility of operation since they allow the system to be operated at higher pressure losses.

The carbon dosage required depends on the strength of the wastewater feed and the desired effluent quality. Rough estimates of the carbon dosage required for secondary biological effluents plus filtration are 400-600 lbs/million gallons ($48-72 \text{ Mg/m}^3$) of wastewater (11).

Bench scale tests determine more quantitatively the carbon dosages needed to produce a desired effluent. The carbon column contact time (empty bed basis) is generally 10-50 gpm/ft² (6.8×10^{-3} to $3.4 \times 10^{-2} \text{ m}^3/\text{S/m}^2$) (11).

5.3.2.3.3 Reverse Osmosis

The reverse osmosis process is capable of removing particles from water in the range of 0.0004-0.06 microns. Removal efficiencies range from 90 to 99+ percent in most cases (12).

The principal use of reverse osmosis is for purification of brackish waters. It is also used as water pretreatment for ion exchange deionization to make ultrapure water for subsequent use as boiler feed, cooling tower makeup, and washwater of essentially zero hardness. Organic matter is also removed by this process which offers a significant advantage over demineralization systems such as ion exchange or electrodialysis.

Measures required to reduce the incidence of membrane fouling represent a significant disadvantage of the reverse osmosis process in terms of operation and cost. Membrane fouling is due to biological growth, manganese and iron, suspended solids scale, and/or organics. Pretreatment is generally required to reduce the incidence of fouling which

consequently increases the capital and operating costs considerably over other processes. Pretreatment measures commonly used are chlorination to control biological growth, polishing filters to reduce suspended solids levels, softening to reduce scale, and precipitation of iron and manganese as ferric hydroxide and manganese dioxide.

The most important parameters considered in the design of a reverse osmosis plant include recovery, product water quality, brine flow rates, the necessary degree of pretreatment, flux maintenance procedures, and post treatment.

The design flux, expressed in $\text{m}^3/\text{m}^2/\text{day}$, is a function of the feed composition, temperature, and pressure. Given the operating conditions and influent flow rate, the membrane area required can be determined. Membrane manufacturers should supply this data. The product water quality can be determined by iterative techniques from the following equations (12):

$$1. \quad C_{ip} = \frac{C_{ip} (1 - (R_i)_{avg})}{Z - \left(\frac{Q_p}{Q_f} \right)}$$

$$2. \quad Q_f = Q_c + Q_p$$

$$3. \quad Q_f C_{if} = Q_c C_{ic} + Q_p C_{ip}$$

$$4. \quad C_{im} = \frac{Q_c C_{ic} + Q_f C_{if}}{Q_c + Q_f}$$

$$5. \quad C_{ip} = C_{im} (1 - (R_i)_{avg})$$

where

C_{ip} = concentration of salt i in product stream (mg/l)

C_{if} = concentration of salt i in feed stream (mg/l)

Q_p = volumetric flow rate of product stream (l/min)

Q_f = volumetric flow rate of feed stream (l/min)

$(R_i)_{avg}$ = average salt rejection by membrane

C_{im} = mean local brine concentration on upstream side of membrane (mg/l)

C_{ic} = concentration of salt i in concentrate stream (mg/l)

Q_c = volumetric flow rate of i in concentrate stream (l/min)

Pretreatment and post-treatment methods are designed based on influent water constituents and effluent limitations.

5.3.2.3.4 Ion Exchange

Ion exchange is a process whereby ions that are held by electrostatic forces to charged functional groups on the surface of a solid are exchanged for ions of similar charge in a solution in which the solid is immersed. This process is used extensively in water and wastewater treatment, primarily for the removal of hardness ions such as calcium and magnesium. A series of cationic and anionic ion exchangers (demineralization) are also often used to produce water of high purity for industrial applications.

The design of ion exchangers is based on the ion exchange capacity of the selected ion exchange resin. The basic resin usually consists of a three dimensional matrix of hydrocarbon radicals to which are attached soluble ionic functional groups. There are two types of ion exchange resins, namely, cationic and anionic. Cationic resins have positively charged functional groups such as hydrogen or sodium attached to the hydrocarbon radicals, while anionic resins have negatively charged functional groups such as hydroxide or chloride ions attached to the hydrocarbon radicals. The ability of the resin to adsorb ions is the ion exchange capacity expressed in kg/m^3 . Each resin has a different capacity which must be specified by the manufacturer of the resin. Also, resins have observed preferences for certain ions which must be considered in the selection of a particular resin.

Once the resin has been selected, the volume of resin required may be determined from the following equation (12):

$$R = \frac{QT}{C}$$

where:

R = cubic ft. of resin required

Q = equivalents of ions which must be removed per day to meet certain effluent limitations (i.e. 90-99 percent removal for two stage operations)

T = selected operating period (days) beyond which the effluent limitations will be exceeded and the resin requires regeneration (economic selection based on cost of regeneration chemicals and required removal efficiency)

C = ion exchange capacity of resin in equivalents/day

The depth of the exchanger is usually at least 50 percent greater than the depth of the resin to allow for expansion during backwash and regeneration (12).

Other factors to be considered in the design of ion exchangers are the flow rate and volume of chemicals needed to regenerate the ion exchange resin. Flow rates of 6-10 gpm/ft² (4.1×10^{-3} to 6.8×10^{-3} m³/S/m²) are typical (12). Typical regenerant solutions are sodium chloride, sulfuric acid, sodium hydroxide, sodium carbonate, ammonium hydroxide, and hydrochloric acid. Cost considerations and type of ion exchanger dictate the chemicals to be used. Since it is not the intention of ion exchangers to remove large quantities of suspended solids, filtration usually precedes the ion exchange process. If filtration was not normally required for a particular wastewater, then it must be included in the cost considerations for selecting the ion exchange process.

Typical removal efficiencies for the ion exchange process preceded by biological treatment and filtration are given in Table 18.

TABLE 18. ION EXCHANGE PROCESS (4)

Wastewater Constituent	Percent Removal
BOD	40-60
COD	30-50
NH ₃	85-98
organic nitrogen	80-95
NO ₃	80-90
PO ₄	85-98
dissolved solids	depends on resin

5.3.2.3.5 Electrodialysis

The electrodialysis process is capable of removing particles in the range of 0.0004-0.1 microns (4). The removal efficiency for wastewaters which have been treated by biological processes, filtration, and carbon adsorption is approximately 40 percent (4).

Parameters used in the design of electrodialysis systems are dilute cell compartment velocity, cell power input, cell current, product concentration, current efficiency, cell resistance. Experimental analyses are usually performed for a significant wastewater constituent such as sodium chloride. The first four parameters listed above are measured in a specific volume electrodialysis cell. The current efficiency, required membrane area, power requirements, and energy requirements may be determined from the following equations using the experimental results (12).

$$1. \quad n = \frac{Q_d (\Delta N_i) F}{I}$$

2. $Q_d = WtI$
3. $A_p = \frac{Q_d F}{(1000)n} \left(\frac{N_d}{i_{lim}} \right) \ln \frac{N_f}{N_p}$
4. $R_p = (P/I^2) LW$
5. $i = I/A_o$
6. $\bar{P} = \frac{Q_d^2 F^2}{A_p} (N_f - N_p) \left(\frac{(R_p N_d)}{n^2} \right) \ln \left(\frac{N_f}{N_p} \right)$
7. $N_a = \frac{C}{1000(MW)}$
8. $E = P/Q_d$
9. $N_o = Q/24(Q_d)$
10. $A = N_o A_p$
11. $\bar{P}_t = P N_o$

where:

- Q_d = flow rate in dilute compartment (ml/sec)
- $\Delta Ni = N_f - N_p$ = difference in feed and product water normalities
- F = Faraday's constant = 96,500
- I = input current (amps)
- n = current efficiency
- W = width of test cell (cm)
- t = thickness of test cell (cm)
- A_p = effective required cell area (cm²)
- N_d = waste product concentration of wastewater constituent (equivalents/l)
- i_{lim} = limiting current density = i (amps)

N_f = feed wastewater constituent concentration
(equivalents/l)

N_p = effluent wastewater constituent concentration
(equivalents/l)

R_p = cell area resistance (ohm-cm²)

C = concentration of wastewater constituent
(gm/equivalents)

MW = molecular weight of wastewater constituent
(gm/equivalents)

E = energy requirements (kWhr/1000 gal product)

N_o = number of cells required

A_o = area of test cell (cm²) = LW

P_t = total power required (KW)

P = test power (W)

A_o = area of test cell (cm²)

L = length of test cell (cm)

N_a = definition of normality of wastewater constituent
(equivalents/l)

P = power required per cell (W)

5.3.3 Control Module Selection

There are numerous liquid wastewater streams discharged from coal liquefaction processes which may be highly variable in both volume and chemical composition. Wastewater streams in the SRC process result from hydrogen production, gas purification, cryogenic separation, auxiliary facilities (cooling towers), hydrotreating, and phase (gas) separation. Typical steam constituents are ammonia, hydrogen sulfide, phenols, organic compounds, oils and grease, heavy metals,

cyanides, suspended solids, chemical additives such as MEA, polyrad, and oleyl alcohol, carbon dioxide, trace elements, sulfates, phosphates, nitrates, organics, nitrogen and sulfur, and alkalinity.

In order to select pollution control equipment which will be application to SRC process wastewaters, an integrated analysis of the various primary, secondary, and tertiary treatment processes discussed in this section must be undertaken with regard to the following considerations:

- What are the effluent limitations which will be imposed on the SRC plant in Illinois?
- Is it more cost effective to treat the wastewaters to a level where the effluent can be recycled to the SRC process rather than discharged to the river?
- What are the various combinations of treatment units, i.e. primary, secondary, and tertiary which will produce the required effluent quality?
- What types of similar equipment can be interchanged and still produce the same quality effluent?
- What types of equipment can be used to produce the required effluent most cost effectively?

The following selection of pollution control equipment is based on providing effective operation of the entire treatment facilities, and producing an effluent acceptable for discharge and/or plant reuse. Only those essential units needed to produce an acceptable effluent are included.

Basic treatment processes which may be used to treat wastewaters from the SRC process to acceptable limits for discharge include hydrogen sulfide and ammonia steam stripping, gravity oil separation, equalization, neutralization, dissolved air flotation and biological treatment. There are two alternative biological treatment systems, namely extended aeration and aerated lagoons. The efficiencies are roughly the same for each of these systems as long as the lagoon is followed by a settling basin. Cost considerations will determine which of these systems may be used. The extended aeration system may also require tertiary treatment such as filters which must be considered in the cost and analysis of the two processes.

In addition to determining the treatment units necessary to produce an effluent acceptable for discharge, one must also consider those treatment units which would be required to reduce wastewater parameters to levels acceptable for plant reuse. A cost comparison of the two systems would then determine which is feasible. Obviously, it is more advantageous (economically) to recycle plant wastewaters when effluent limitations are more stringent than the effluent quality required for plant use.

In view of the stringent effluent limitations which would be imposed on a SRC plant located on the Wabash River, and raw water treatment costs, it appears that plant wastewater recycle is the only viable alternative. Also, the treatment units required would be similar to those previously discussed; therefore, only treatment systems capable of producing an effluent acceptable for plant reuse will be considered further.

5.4 Solids Treatment

5.4.1 Introduction

This section deals with the selection of pollution control equipment which is applicable to the treatment of sludges generated within the SRC plant and from the operation of the wastewater treatment facilities. A representative survey of applicable equipment has been included.

5.4.2 Pollution Control Equipment

Solids treatment encompasses solids volume reduction and/or treatment processes designed to render solid wastes harmless for ultimate disposal by improving their handling characteristics, reducing their volume, and/or reducing their leachability. Typical control equipment available to accomplish these objectives is listed in Table 19. Each type of equipment is discussed separately.

5.4.2.1 Volume Reduction Processes

Sludge volume reduction processes are, most often, essential components of a wastewater treatment facility when a significant quantity of sludge must be disposed of. Economically, it is more advantageous to dispose of sludge which has a low moisture content and is relatively compact. The dewatering equipment listed in Table 19 is capable of providing a significant reduction in the moisture content of wastewater sludges.

TABLE 19. SOLIDS TREATMENT

<u>Volume Reduction Processes</u>	<u>Treatment Processes</u>
thickeners	wet oxidation
filter press	pyrolysis
centrifuges	incineration
rotary vacuum filter	lime recovery
lagoons	heat drying
other systems:	
moving screen concentrators	
belt pressure filters	
capillary dewatering	
rotating gravity concentrators	

The selection of dewatering equipment depends on the characteristics of the sludge, the method of final disposal, availability of land, and economics involved.

5.4.2.1.1 Thickeners

There are three basic classes of thickeners: gravity, dissolved air flotation, and centrifugal. Design parameters for each class of thickener are given in Table 20 (9). Performance of these units is dependent upon the solids loading, hydraulic loading, and removal efficiencies.

Dissolved air flotation thickeners are preferred over gravity thickeners because of their reliability, thicker product, higher solids loading, lower capital cost, and better solids capture. The operating costs, however, are higher for the flotation unit. Centrifugal and dissolved air-flotation units are generally used for excess activated sludge while gravity units may be used for both primary and excess activated sludge.

5.4.2.1.2 Filter Press (Pressure Filtration)

The design of filter presses depend on the quantity of waste sludge to be processed and the desired daily filter press operating period. Often, chemical conditioning agents must be added to the sludge prior to being applied to the filter press to aid in the dewatering process. Typical aids are ferric chloride ash, and lime. It has been observed that the moisture content of pressed sludges ranges from 40-70 percent (9).

Approximately 1 to 3 hours is required to press a sludge to the desired moisture content (4). The whole process, including the time required to fill the press, the time the press is under pressure, the time to open the press, the time required to wash and discharge the cake, and the time required to close the press varies from 3-8 hours (4).

Advantages of this process are high cake solids concentration, improved filtrate quality, improved solids capture, and reduced chemical consumption. Disadvantages include batch operation, high labor costs, filter cloth life limitations, operator incompatibility, and cake delumping.

TABLE 20. THICKENERS

Parameters*	Class			
	Gravity	Dissolved Air Flotation	Disc	Centrifugal Solid Bowl
Hydraulic loading (gpm/ft ²)	.28 - .625	0.8 (max acceptable)	NA	NA
Solids loading (lb/hr/ft ²)	P. 20-39 A.S. 4-8	2-3	NA	NA
Air/Solids rates	NA	0.02-0.03	NA	NA
Present solids inlet	P. 2.5-5.5 A.S. .5-1.2	0.5-1.2	.7-1.0	.5-1.5
Percent solids outlet	P. 8-10 A.S. 2.5-3.0	4	4-7	5-13
Percent solids recovery		90	80-97	65-95
Recycle ratio (percent)	NA	30-150	NA	NA
Pressure (psig)	NA	40-80	NA	NA
Flow range (gpm)	NA	NA	50-400	10-160
Detention time (hrs)	24	0.33	NA	NA
Thickener depth (ft)	10	NA	NA	NA

P. = Primary sludge

A.S. = Activated sludge

N.A. = Not applicable

*Data presented are typical parameters used for domestic wastewater solids. Consequently, thickeners do not have to be designed strictly within these limits. Also, data on dissolved air flotation and centrifugal units are presented for excess activated sludge. Metric conversion factors are given in Appendix A.

5.4.2.1.3 Centrifuges

The three basic types of centrifuges which may be used to dewater sludges include solid bowl (countercurrent and concurrent), basket and disc. Polymeric flocculants are most often used with this type of equipment. The use of flocculants is dependent upon the characteristics of the sludge to be dewatered.

Hydraulic capacities and applications of the three types of centrifuges are given in Table 21. The theoretical maximum capacities of these centrifuges are given by the following equations (9,13):

For basket and solid bowl centrifuges;

$$T = \frac{L_e w^2}{2g} (3r_2^2 + r_1^2)$$

For disc centrifuges;

$$T = \frac{2 n w^2}{3g \tan \theta} (r_o^3 - r_i^3)$$

where*

T = theoretical capacity

L_e = effective length of settling zone (ft)

w = angular velocity in centrifugal zone (radian/sec)

r_2 = radius of inside wall of cylinder (ft)

r_1 = radius of the free surface of the liquid layer in the cylinder (ft)

g = acceleration of gravity (32.2 ft/sec²)

n = number of spaces between discs

d = half the included angle of the discs

r_o = radius of outside measure of the disc (ft)

r_i = radius of inside measure of the disc (ft)

*Metric conversion factors are given in Appendix A.

TABLE 21. CENTRIFUGES (13)

Centrifuge	Hydraulic Capacity*	Comments	Application
Basket	up to 60 gpm decrease to 40 gpm	solids - 1% 3-5% solids	metal hydroxide wastes, aerobic sewage sludges, water treatment alum sludges
Solid Bowl	to 400 gpm as low as 75 gpm	lime sludges sewage sludges	raw primary or mixed primary & biological sludges (domestic), anaerobically digested primary or mixed sludges, and heat-treated or limed chemical sludges. It may be applied at high cost to excess activated sludge, aerobic digested sludges, and alum or ferric chemical sludges. In water treatment, it is excellent on water softened lime sludges.
Disc	20-300 gpm 400 gpm	normal maximum	Excess activated sludge for feed concentrations of 0.3 to 1.0 percent suspended solids

*Metric conversion units are given in Appendix A.

Variables of importance which affect the performance of centrifuges include bowl design, bowl speed, pool volume, conveyor design, relative conveyor speed, and sludge feed rate. The hydraulic loadings which may be applied to each centrifuge is a function of Q/T , where, Q is the flowrate and T (defined above) is the theoretical capacity of the centrifuge.

Solids concentrations of 15 to 40 percent have been observed from various centrifuges (9). Solids capture ranges from 80-95 percent for oxygen activated sludges (9). For excess activated sludges, a higher degree of dewatering may be expected from a basket centrifuge than from a disc centrifuge. Typically, basket centrifuges have been found to concentrate solids in the range 0.5-1.5 percent to approximately 10-12 percent (9). Given the same sludge, disc centrifuges can concentrate the solids to only 6 percent (9). Also, 90 percent solids capture is possible in the basket centrifuge with no chemical addition (9).

In many cases, two or more types of centrifuges may be operated in series to increase the solids concentration of sludges. A typical design may include a disc centrifuge to thicken a sludge followed by a solid bowl centrifuge.

Disc centrifuges have a high clarification capability but possess an upper limit on the size of particle which can be handled. Feed waters should be degrittied and screened prior to entering this equipment.

5.4.2.1.4 Rotary Vacuum Filters

Rotary vacuum filters consist of a cylindrical rotating filter partially submerged in an open tank filled with the slurry to be filtered. The filter elements can be coated with a substance such as diatomaceous earth or other precoat material so that particles much finer than the openings in the filter element can be retained.

Vacuum filters operate at low differential pressures, on the order of 6-10 psi (0.04-0.07 MPa) (9). When a precoat substance is utilized on a vacuum filter, particles down to about one micron in diameter can be removed, resulting in very clean effluents. Influent slurries, however, usually must be limited to less than a one precoat solids concentration. The vacuum filter can be cleaned by hosing, internal sluicing, or air pump backwashing.

The use of vacuum filters is governed by the media's opening and size distribution of particles in the sludge. It has been observed that the solids captured by vacuum filters may range from 85-99.5 percent depending on the type of filter media, chemical conditioning, and solids concentration in the applied sludge (9). Cake yields usually range from 2-15 lb/hr/ft² (2.7 - 20 g/s/m²) for domestic sludges (9). The surface area of vacuum filters generally ranges from 50 to over 300 ft² (4.6-28 m²) (9). Estimated performance for design purposes is usually taken to be 3.5 lb/hr/ft² (4.7 g/s/m²) (dry weight basis) (9).

The filtrate discharge rate and cake thickness left on the filter may be calculated by the following equations (13):

$$Z_c = 60n \frac{V_f}{A} = \left[\frac{7200(\Delta P)Bn}{a\mu W} \right]^{1/2}$$

$$L_c = \frac{1}{60cn} \left[\frac{7200B(\Delta P)nW}{a\mu} \right] - Z_c W_f$$

where*

Z_c = filtrate in gph/ft² total area

n = cycles per minute

V_f = volume filtrate (gal)

A = filter area (ft²)

P = pressure differential maintained across the leaf (psi)

B = fraction of total area actually being filtered at any given time

a = specific resistance of cake (to be calculated)

μ = viscosity of filtrate (lb/sec-ft)

W = mass of dry solids/volume of slurry (lb/gal)

ρ_c = density of cake (lb/ft³)

W_f = solids content of filtrate (lb/gal filtrate)

L_c = cake thickness (ft)

*Metric conversion factors are given in Appendix A.

The quality of the filter cake is measured by the percentage moisture content of the cake on a weight basis. A typical range of moisture contents which may be expected from this equipment is 60-80 percent (9).

Typical chemical conditioning agents for the raw sludge are lime and ferric chloride.

5.4.2.1.5 Lagoons

Drying lagoons are most ideally used where there is a great deal of land and the climate is hot and arid. Lagoon depths are generally not more than 24 inches (0.6 m) with loading rates of 2.2-2.4 lb/ft³/yr (35-38 kg/yr/m³) (9). Sludge can usually be removed from the lagoon in 3 to 5 months (9). If it were feasible to load a lagoon for a period of 1 year and allow a drying period of 2-3 years, then it is conceivable that the applied sludge may be dewatered from 5 percent to 40 to 50 percent solids (9). An obvious disadvantage of this method is the extensive time required to obtain the desired product.

5.4.2.1.6 Other Systems

There are four types of dewatering systems manufactured by various companies which do not fall into any of the previous categories. They include moving screen concentrators, belt pressure filters, capillary dewatering, and rotating gravity concentrators.

Moving screen concentrators are capable of processing 400-800 lb/hour (182-364 kg/hour) of excess activated sludge and 800-1600 lb/hour (364-728 kg/hour) of primary sludge (9). These concentrations have been reported to increase the solids content of primary sludges to 20 to 30 percent (9). Typical yields vs. sludge cake solids are shown in Figure 9. These units handle thickened polymer treated sludges.

Belt pressure filters have been reported to produce mixed sludge concentrations of 25 to 30 percent (9). Polymer aids are generally used with these filters.

Pilot scale studies on domestic sludges using capillary dewatering systems have indicated that loading rates of 2-5.4 lb/hr/ft² (7.25 g/s/m²) will produce cake solids of 14-19 percent with solids recoveries of 50-90 percent (9). Polyelectrolytes and ferric chloride were used as filter aids in these systems.

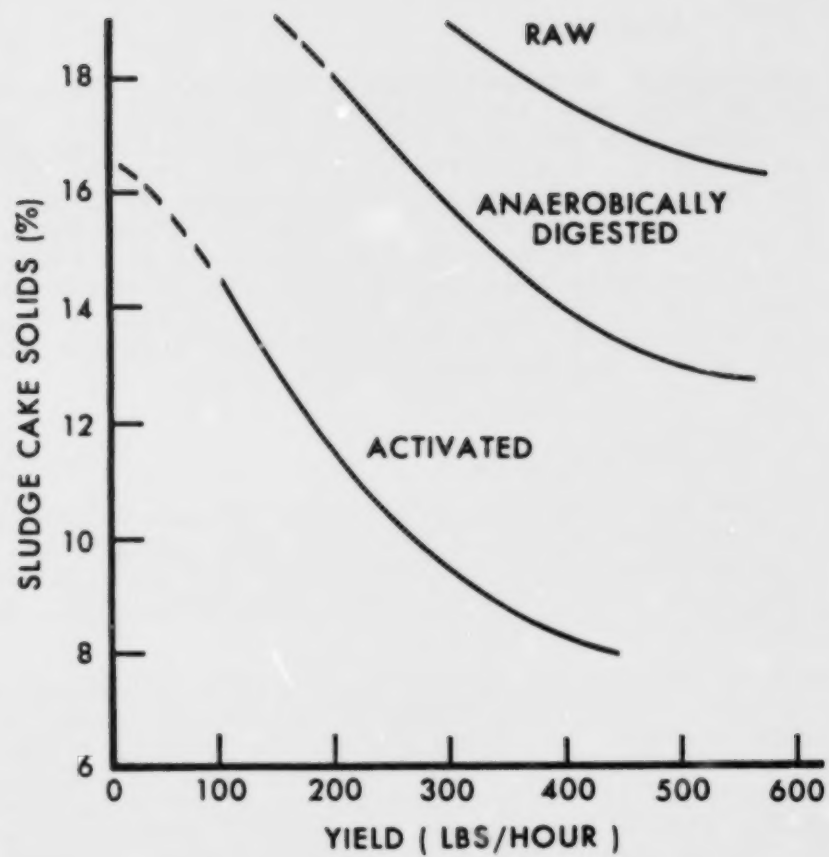


Figure 9. Moving Belt Concentrator Yield
vs. Cake Solids

The rotating gravity concentrator has been mainly employed as a concentrating device when more complete dewatering was required. In one instance, it was reported that a 25 percent filter cake was produced from a 6 percent raw primary sludge (9). A disadvantage of the system is the short life of the dewatering belt.

5.4.2.2 Treatment Processes

In addition to dewatering equipment there are numerous processes which may be required in a wastewater treatment plant to render solids wastes harmless prior to ultimate disposal, to recover valuable chemicals, and/or to make subsequent processes operate more efficiently. Typical processes include heat drying, wet oxidation, pyrolysis, incineration, and lime recovery. In many cases, one or more of these processes may be combined with appropriate dewatering equipment to produce sludges acceptable for ultimate disposal.

5.4.2.2.1 Heat Drying

Heat treatment may be used in lieu of chemical pretreatment to improve the dewatering characteristics of sludges. In this process, sludge may be thickened to approximately 7 to 11 percent by breaking down particle structures within the sludge. Operating conditions are generally 360°F (182°C) and 180 psig (1.2 MPa) (14). The detention time is approximately 30 minutes (14). Up to 100 gpm (379 liters per minute) can be processed by this method. It has been observed that, in many instances, the moisture content of sludges may be reduced to lower levels by using heat drying than by chemical addition.

5.4.2.2.2 Wet Oxidation

The wet air oxidation process is based on the principle that any substance capable of burning can be oxidized in the presence of liquid water at temperatures of 250-700°F (121-371°C). It is excellent for waste sludges which do not dewater easily. Typical operating conditions are given in Table 22. Figures 10, 11, and 12 provide operating conditions as a function of each other.

TABLE 22. WET AIR OXIDATION PROCESS
OPERATING CONDITION (14)

Operating Condition	Value(s)
Feed COD	25-150 g/l
Temperature	149-316°C
Pressure	2.1-13.7 MPa
COD reduction	5-80%
VSS reduction	30-98%

Four important parameters which control the performance of the oxidation process are temperature, air supply, pressure, and free solids concentration. The degree and rate of sludge solids oxidation are significantly influenced by the reactor temperature. It has been observed that higher degrees of oxidation and shorter retention times are possible with increased temperatures. The air requirements are based on the heating value of the sludge and the degree of oxidation desired. Operating pressures must be carefully controlled to prevent excess water vaporization in the oxidation reactor.

Advantages and disadvantages of the process are listed in Table 23.

TABLE 23. WET OXIDATION PROCESS

Advantages	Disadvantages
does not require dewatering no air pollution	need stainless steel construction materials
produces easily filtered and biodegradable end products	need to recycle wet air oxidation liquors, high in organic content, phosphorus, and nitrogen back through the plant
potential to generate or recover steam, power and chemicals	
flexible in degree of oxidation and type of sludge handled	possible frequent shut-down and maintenance problems
	odor problems

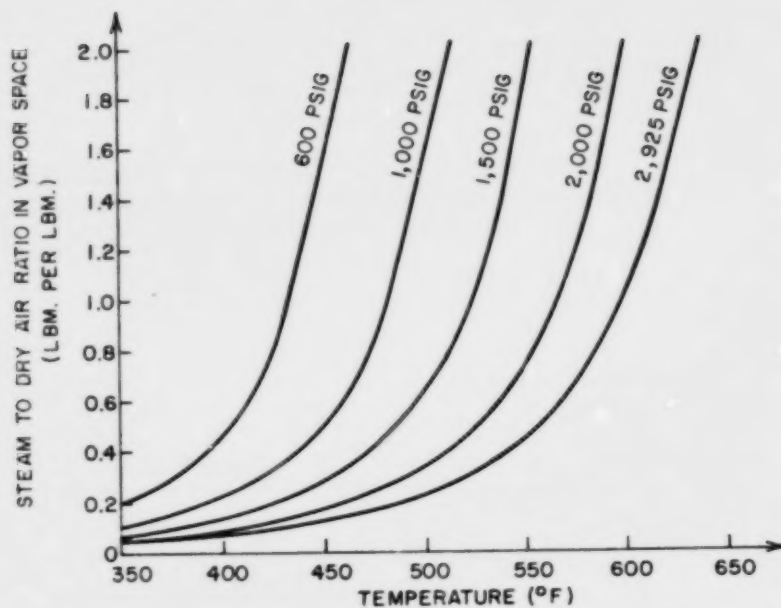


Figure 10. Steam-to-Air Ratio at Saturation in the Reactor Vapor Space for Various Operation Temperatures and Pressures (14)

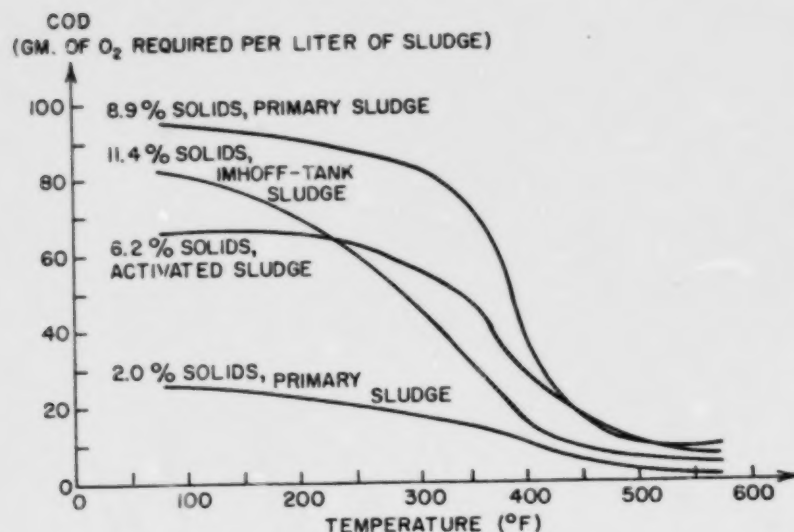


Figure 11. Reduction in COD Resulting from Sludge Being Exposed to Excess Air for One Hour At Various Temperatures (14)

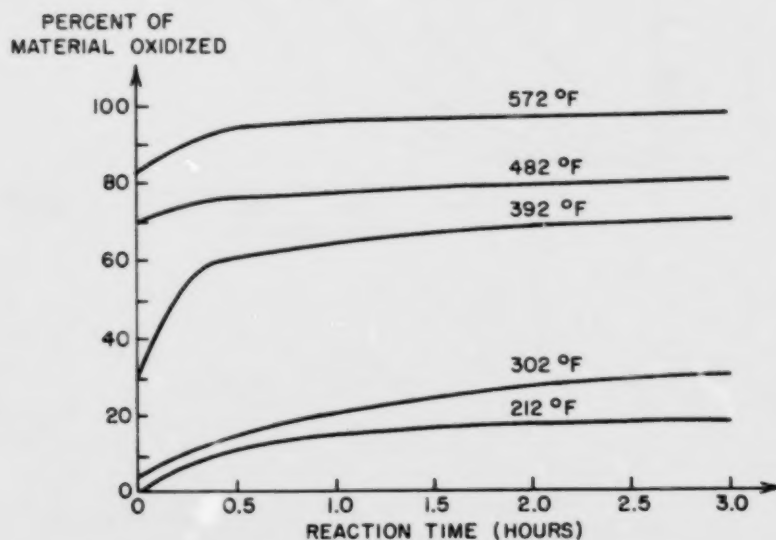


Figure 12. High Operation Temperatures Result in High COD Reduction and Low Reaction Time (14)

5.4.2.2.3 Pyrolysis

Pyrolysis involves the destruction of longchain organic materials by high temperature exposure. Retorts, rotary or shaft kilns, or fluidized beds are used to pyrolyze waste sludges. This process has been proposed as an alternative to incineration since it partially disposes of solid wastes. Volume reduction also occurs in the process. It has an advantage over incineration methods because it eliminates air pollution problems and produces useful by-products. Little data has been published, as yet, on the pyrolysis of sludges.

5.4.2.2.4 Incineration

Incineration is a two stage process including drying and combustion. It is most often used to render offensive sludge wastes harmless so that the sludge may be safely disposed of in landfills. The most commonly used incineration processes are the multiple hearth furnace and the fluidized bed burnace.

Considerations important in the design of incineration processes are the following:

- familiarity with state and local air and water quality regulations and with occupational, health and safety standards
- nature and amount of sludge to be incinerated
- applicability of incineration processes to sludge treatment
- auxiliary fuel and excess air requirements
- economics

The composition of industrial sludges may vary so widely from one plant to another that standard incineration processes are usually not applicable. Hence, special incinerators must be designed to handle the complex compounds found in these sludges. Often more than one incinerator must be provided to combust complex organic materials formed in the first incineration process.

Multiple hearth furnaces have been adapted to numerous uses including burning of raw sludge, digested sludge and sewage greases; recalcination of lime sludges; and pyrolysis operations. Capacities generally range from 200-8000 lb/hr (91-3636 kg/hr) dry solids (14). Combustion zone temperatures range from 1400-1700°F (760-927°C) (14). Fluidized bed incinerators are most often used for sewage sludge disposal. Capacities range from 220-5000 lb/hr (100-2273 kg/hr) dry solids (14). Operating temperatures range from 1300-1500°F (704-816°C) (14).

Although well-designed incinerators are relatively simple to operate and maintain, a major disadvantage resulting from the process is the air emissions which must be controlled. Advantages and disadvantages of incineration are listed in Table 24.

TABLE 24. INCINERATION

Advantages	Disadvantages
Less land required for disposal of incinerated sludges	Large initial expenditures
Incinerator residue is free of food for rodents and insects	Disposal of remaining residue must be provided
Incinerators can burn a variety of refuse materials	Air pollution
Adverse weather conditions should have no effect on incineration process	Possible incomplete reduction of waste materials
Incineration construction is flexible	High stacks needed for natural draft chimneys present safety problems

5.4.2.2.5 Lime Treatment

Lime treatment is a process whereby lime is recovered from a waste sludge. Economic considerations dictate whether or not this process should be included in industrial wastewater treatment facilities.

The lime treatment process typically includes dewatering devices such as thickeners or vacuum filters, centrifuges, a furnace, lime cooler, classifier, and lime storage unit. The design of thickeners, vacuum filters, and furnaces has been previously discussed. Contactive (direct) heat transfer methods may be used to cool the resultant furnace residue prior to directing it to the classifiers. Centrifuges (also previously discussed) may be used prior to

the furnace to purge the sludge of inert solids. They also reduce the required furnace volume. Dry classifiers are used after the furnace to separate the calcium oxide from the residue. This is accomplished by air separations based on particle size. The regenerated calcium oxide is then sent to a lime storage tank for reuse.

5.4.2.2.6 Control Module Selection

There are numerous sludges produced within an SRC plant for which pollution control measures must be selected. Typical sludges are listed in Table 25. Each type will be subsequently discussed.

TABLE 25. SRC SLUDGES

<u>Sludge</u>	<u>Origin</u>
Lime sludge	Raw water treatment
Slag	(Hydrogen production, gasifier, venturi scrubbers)
Spent catalyst	Hydrotreating
Reactor sludge	Bottom of vessels such as fractionation tower.
Residue	Solids separation

Lime sludges are produced as a result of the addition of lime to raw water. It contains large quantities of calcium carbonate as well as magnesium hydroxide, calcium hydroxyapatite, suspended solids, detergents, and metals if they are present in the raw water.

Prior to disposal, lime sludges usually require dewatering as the solids content is only 4-5 percent. Typical equipment which may be used to decrease the moisture content of these sludges are thickeners and centrifuges.

An alternative to dewatering is the recovery of lime from the sludge. Equipment which may be used to recover the lime are discussed in this section. An economic analysis of dewatering vs. recovery must be undertaken to determine which of the two methods is most economically feasible.

There are no control measures (dewatering or treatment) which must be applied to slag, spent catalyst or reactor sludges prior to disposal. Ultimate disposal methods applicable to these sludges may, however, require special containment or disposal techniques.

A considerable amount of residue is discharged from the solids separation area. It is apparent that the production of fuel gas from the residue is much more feasible an alternative than treating this waste sludge by incineration or pyrolysis prior to disposal. The slag which results from the production of fuel gas probably will not require any further control measures prior to ultimate disposal.

5.5 Final Disposal

5.5.1 Introduction

Ultimately, all materials discharged from a coal liquefaction plant must be returned to the environment via air, land, and/or water. The mechanisms by which wastes are discharged to air and water have been thoroughly discussed under the liquid, air, and solid waste treatment sections. A general summary, therefore, on final disposal to air and water is presented here. Mechanisms of ultimate disposal of wastes to land have not been previously discussed. Consequently, a survey of various methods will be presented in this section.

5.5.2 Disposal to the Air

Biological and thermal decomposition of organic and inorganic materials are mechanisms by which numerous compounds are ultimately disposed of to the atmosphere. As discussed in the Gaseous, Liquid, and Solid Waste Treatment sections, there are a significant number of sources of gaseous waste emissions discharged from coal liquefaction processes which must be further processed prior to discharge to the environment. As indicated in the Solid Waste Treatment section, there are also several possible sources of emissions to the atmosphere as a result of sludge treatment depending on the types of sludge treatment units employed.

The volume and characteristics of wastes which may be discharged to the atmosphere are dictated by local, state, and federal regulations.

The effects of discharge of gaseous wastes to the environment may be mitigated by their dispersion into the atmosphere. Tall stacks may discharge wastes at such an elevation that they will be completely dispersed by natural elements such as wind and precipitation before they reach the ground. Also equipment may be placed in the stack to aid in the dispersion of gaseous wastes into the atmosphere.

5.5.3 Disposal to Water

Surface water discharge to lakes, rivers, or estuaries, deep well injection, and ocean dumping represent the most common mechanisms by which wastes are discharged to water. Surface water discharge is the most accepted and widely used method since severe restrictions have been placed on the use of ocean dumping and deep well injection. The volume and characteristics of wastes which may be discharged to water courses are dictated by local, state, and federal regulations.

Controlled waste discharges to water generally result from the operation of wastewater treatment facilities. Accidental spills also represent a possible source of wastes discharged to water.

5.5.4 Disposal to Land

There are numerous wastes resulting from coal liquefaction processes and from the operation of wastewater treatment facilities which may be ultimately disposed of on land. Wastes discharged to land may be in the liquid or solid phase. Typical land disposal methods include spreading on soil, lagooning, dumping, landfilling, composting, spray irrigation, and evaporation ponds. The first five are considered sludge disposal techniques while the latter two are considered liquid waste disposal techniques. State, federal, and local regulations, availability of land, applicability of ultimate disposal processes, and economics will dictate which of the aforementioned methods may be employed to ultimately dispose of liquid and solid wastes.

5.5.4.1 Sludge Disposal

Land disposal of sludges includes the application of sludge on soils used for crops or other vegetation, and the stockpiling of sludges on land. Stockpiling refers to the disposal of sludges in mines, quarries, landfills, and permanent lagoons. An inherent disadvantage of land disposal is that it is not a permanent solution because the sites fill and new locations must be found.

5.5.4.1.1 Land Spreading

Land spreading encompasses the disposal of sludge on soils used for crops or other vegetation and on lands occupied by abandoned strip mines. Sludge may be spread on the land as a soil conditioner or as an organic base for fertilizers (biological sludges). It also serves as a source of irrigation water. Other areas where land spreading may be applicable are forest regeneration, development of new parklands and institutional lawns, and top dressing for parklands.

There are six acceptable methods of land application including: plow furrow cover, contour furrow, trenching, subsod injection, spray or flood irrigation, and spreading (solid) (15). The application method selected will depend on physical properties of the sludge, quantity of sludge, acceptable application rate, site characteristics, crops grown, site management, and public acceptance. Land spreading of both liquid and dewatered sludges are feasible by the above methods. An analysis of liquid sludge transport costs vs. dewatering equipment costs must be undertaken when there are no regulations restricting the moisture content of the sludge to determine the most economic means of sludge disposal.

Spray and flood irrigation systems are applicable only to the disposal of liquid sludges. This method may be used year round with proper maintenance on crop covers located on 0.5-1.5 percent sloping lands (15). Power requirements may be significant when stationary application systems are used. Flood irrigation is less costly than spray irrigation, but can only be used in basin shaped sites. Problems resulting from this method include fly breeding, odors, and a tendency of solids to settle out near the outlets.

The plow furrow cover method may be used for both liquid and dewatered sludge application. Sludge may be applied in a plow furrow manner using trucks, wagons or irrigation systems. This method eliminates odor and pest problems but is not usable on wet or frozen soils and on highly sloped lands.

Contour furrows are normally used for the application of liquid sludges. This method leaves the soil in only a partially plowed condition.

Subsurface injection is reserved for the disposal of liquid wastes. The site must be level or slightly sloped and must not be wet, hard, or frozen.

Trenching may be used for both liquid and dewatered sludges. Problems encountered with this method include possible groundwater pollution and difficulty in keeping the sludge where placed during backfilling operations.

Spreading applies only to the disposal of dewatered sludges. This method encompasses the spreading of sludges on reasonably dry solid surfaces with bulldozers, loaders, graders or manure spreaders, and plowing it under.

It has been recommended that several alternative land spreading methods should be made available at each site to coincide with weather conditions, presence of crops, poor quality sludge (odors) and equipment breakdown.

5.5.4.1.2 Lagooning

Sludge lagooning is a simple and economical method of sludge disposal especially in remote locations. Sludges can be stored, indefinitely in this type of system or removed periodically to other sites after draining and drying. Lagoons are usually 4-5 feet (1.3-1.7 meters) deep. This method is usually feasible only when there are large tracts of land available for dedication to lagoons.

5.5.4.1.3 Dumping

Dumping is a process whereby stabilized sludge is deposited in abandoned mines and quarries. Where available, this provides an alternative to other disposal methods.

5.5.4.1.4

Landfills

Sanitary landfills are the most widely used type of landfill. In many cases, it is permissible to mix domestic and industrial waste sludges for disposal in a sanitary landfill.

Criteria commonly used in the selection of a suitable landfill site include the following:

- The site should have a relatively low permeability and low water table.
- The site should be far enough away from surface water bodies or shallow wells.
- A liner and drain system is recommended at the site.
- The site should be covered with an impervious layer to maximize runoff.
- Vector control should be provided.
- A wooded barrier should be provided.

Sludges applied to a landfill site should be dewatered as much as possible to minimize the quantity of free water which may leach out of the sludge.

Application rates will depend on sludge composition, soil characteristics, climate, vegetation, and cropping practices. Loading rates of 0.5-100 tons/acre (0.056-11.2 kg/m²) are common (14).

Problems associated with the use of landfills include the following:

- groundwater pollution
- surface water pollution
- land requirement
- health hazards
- landfill gases (explosive)
- aesthetic effects on neighboring communities.

5.5.4.1.5 Composting

Composting requires larger tracts of land than other stabilization methods and produces a solid product which must be disposed of. Its uses are similar to those for land spreading, namely, as a soil conditioner and organic base for fertilizers. Considerations with regard to site selection and maintenance are also similar to land application methods previously discussed. Land requirements are 1.5 acres/ton (0.17 m²/kg) of sludge using the forced air, static pile process. Advantages and disadvantages of the process are listed in Table 26.

TABLE 26. COMPOSTING

Advantages	Disadvantages
• odor free product • easy to store product • able to return nutrients and organics to soil • nitrogen levels are reasonably low	• cost of transport to composting site may have high levels of heavy metals • requires large tracts of land • product requires further disposal

5.5.4.2 Liquid Waste Disposal

As previously discussed, liquid wastes may be ultimately disposed of by discharge to surface waters or groundwaters (deep well injection). Liquid wastes may also be discharged to the land by spray or overland irrigation systems and evaporation ponds. These methods are usually considered when there is no direct access to surface waters or when no discharge systems are required due to surface water quality restrictions.

The design of irrigation systems include the selection of a suitable site, cover crop, application rate, and buffer zone. Also, there are usually local restrictions on the composition of the wastes which may be discharged on the land. Advantages and disadvantages of irrigation systems are listed in Table 27. Typical spray irrigation rates are 1 inch/day (2.54 cm/day) with a maximum of 3 inches/week (7.6 cm/week) with BOD loadings of 100-250 lb. BOD/acre/day (11.2-28 kg/m²/day) (13).

Evaporation ponds are usually located in an area where land is plentiful and climatic conditions are conducive to evaporation of wastewaters. Pond sizes will depend on the volume of waste to be disposed of, evaporation rates, rainfall, and percolation rates. In many cases, the wastes may be of such a nature that pond liners may be required. This would eliminate the effects of percolation through the bottom of the pond.

TABLE 27. IRRIGATION SYSTEMS

<u>Advantages</u>	<u>Disadvantages</u>
Relatively low initial costs.	Requires large amount of land.
Low or comparable operating costs.	Applicable to only certain types of soils.
Flexible in quantity and quality of wastes applied.	Can cause odor if wastes are allowed to settle in a pond.
Provides for total treatment of waste effluents.	Waste cannot hamper absorption capacity of the soil.
May be used in cold weather if operated properly.	Groundwater contamination can occur if system is not operated properly.
May be used in conjunction with harvestable crops to subsidize procedure.	
Wastes which are toxic to biological treatment may be handled if managed properly.	

5.5.5 Selection of Ultimate Disposal Methods

5.5.5.1 Disposal to Air

As stated previously, gaseous wastes emitted to the atmosphere will be controlled by stack sizing and dispersion techniques. It is assumed that such design measures will be incorporated into the design of the plant.

5.5.5.2 Disposal to Water

Surface water discharge, deep well injection and ocean dumping are the only ultimate disposal alternatives available for the discharge of wastes to water. Since severe restrictions have been imposed on deep well injection and ocean dumping is totally unfeasible for liquefaction plants located in the midwest, surface water discharge appears to be the only alternative available for discharge of wastes to water. Therefore, in subsequent sections of this report, only surface water discharge will be considered.

5.5.5.3 Disposal to Land

Several ultimate land methods have been presented in this section which must be considered for each anticipated waste discharge to land. Since it has been decided that surface discharge is readily available for discharge of aqueous wastes, spray irrigation and evaporation pond need not be considered further as alternatives for wastewater disposal. Also, many of the solids disposal methods such as spreading on soil, lagooning, and composting are not particularly applicable for many of the solid wastes discharged from the liquefaction plant. In most cases, land-spreading and composting are used when the sludge may be ultimately used as a soil conditioner or fertilizer. None of the slag, lime, or residue sludges discharged from the plant would be suited to these purposes. Waste activated sludge from the waste treatment facilities could be used as a soil conditioner but its volume is so much smaller than the volume of other waste sludges that it would be impractical to consider these alternatives for only one sludge. It would be much more practical to combine this sludge with other sludges prior to disposal.

5.6 Combustion Modification

Combustion modification techniques consist of modifying operating and/or design features of the furnace to obtain optimum control of nitrogen oxides emission. Operating condition modifications include low excess air combustion, two-stage combustion, flue gas recirculation, reduced air preheat, and steam or water injection.

Nitrogen oxides concentrations can be lowered by reducing excess air rates. The effectiveness of low excess air combustion is proven for gas and oil combustion where tests show a 20-30 percent reduction in NO_x when oxygen in the flue gas drops off to 2 percent from 3 to 4 percent (1). No test data is yet available for coal-fired equipment.

Reduction in combustion air limits the availability of oxygen throughout the combustion equipment and increases the burner air-fuel mixture ratio to some extent. Very low NO emissions with fuel oil have been attained with excess air values as low as 2 percent. Simple lowering of excess air does not appear as effective or damage-proof as other modification techniques. In coal firing, serious imbalances in fuel/air distribution may result from low excess air, and problems of unburned fuel or carbon monoxide emissions may limit the utility of this approach. A reduction in emissions of one pollutant may result in an increase of another. Off-stoichiometric combustion has been found to be most effective when applied to larger generating units with larger burners. This is true because essentially all the nitrogen oxides are formed in the primary combustion zone, and as the burner size increases, the primary zone tends to become less efficient (1).

One of the most effective methods for nitrogen oxides control is the two-stage combustion process. In this method, 90 to 100 percent of the theoretical combustion air is injected into the burner. The remaining air is introduced a few feet downstream of the burner to complete combustion over a longer zone. With this arrangement, the total excess air is held to the same value as that of normal firing. By supplying substoichiometric quantities of primary air to the burners in oil and gas-fired combustion, reductions of 40 to 50 percent in nitrogen oxides may be achieved. Complete burnout of the fuel is accomplished by injecting secondary air at lower temperatures, where NO_x formation is limited by kinetics. This technique is best used with low excess air firing. Reductions as high as 90 percent have been achieved using both technologies in large gas-fired power plants. Table 28 shows the effect of two-

stage combustion when natural gas and fuel oil are fired (1). No full scale performance data was available for coal-fired generators.

TABLE 28. EFFECT OF TWO-STAGE COMBUSTION ON EMISSION OF NITROGEN OXIDES FROM A LARGE STEAM GENERATOR AT FULL LOAD (1)

Fuel	Nitrogen Oxides Concentration When All Air Through Burners, ppm by Volume	Two-Stage Combustion			
		Air Through Burners, % Theoretical	Total Air, % Excess	Nitrogen Oxides, ppm by Volume	% Reduction in NO _x Concentra- tion
Oil and gas combined	525	95	7-10	385	27
Oil only	580	90	7-10	305	47

The recirculation of cool flue gas and its injection through the burner is found to be quite effective in reducing nitrogen oxides formation. This technique lowers the peak flame temperatures by diluting the primary flame zone with the recirculated flue gases. A direct reduction of maximum combustion chamber temperature occurs when flue gas recirculation is incorporated with excess air reduction techniques. Nitrogen oxides drop off by a factor of 2 to 3 when flue gas recirculation increases to more than 20-30 percent. Emission concentration levels below 100 ppm are possible with over 25 percent flue gas recirculation. Most existing units are presently limited to 20 percent recirculation, due to superheat and reheat steam temperature elevation (1).

Reducing the air preheat is a means of lowering primary combustion zone peak temperatures and NO_x formation. Limited data for natural gas tangential firing indicates a drop in nitrogen oxides concentration in the order of 20 percent with 100 percent reduction in air preheat. Operational limitations with this technique have not been established, but a basic disadvantage inherent in the system is a reduction in thermal efficiency. This is undesirable, not only from an operational standpoint, but also because more fuel is consumed to generate electrical power or steam (1).

Injection of low temperature water or steam is similar in concept to flue gas recirculation; thermal dilution of the flame can be achieved by this method, resulting in reduced NO_x emissions. This technique appears to have limited utility for furnace control because of operating debits.

The operating condition modifications mentioned above can be used simultaneously. Low excess air and two-stage combustion reduce the quantities of gases reacting at maximum temperatures. Flue gas recirculation and reduced air preheat directly influence maximum combustion temperatures. Limited tests combining off-stoichiometric combustion with gas recirculation on a 320 MW corner-fired unit showed that NO_x emissions could be reduced by 83 percent. However, it was found that the combined conditions necessary to achieve such low levels of NO_x were not compatible with operational procedures. Table 29 summarizes estimated nitrogen oxides reductions that may be achieved when combustion modification techniques are applied to coal-fired boilers (1).

TABLE 29. ESTIMATED PERCENT REDUCTION IN
NO_x EMISSIONS BY COMBUSTION
MODIFICATION OF COAL-FIRED BOILERS (1)

Boiler Size	Low Excess Air	Two-Stage Combustion	Low Excess Air and Two-Stage Combustion	Flue Gas Recirculation	Low Excess Air and Flue Gas Recirculation	Steam or Water Injection
1000 MW	25	35	60	33	55	10
750 MW	25	35	60	33	55	10
500 MW	25	35	55	33	55	10
250 MW	25	30	50	30	50	10
100 MW	25	25	40	30	40	10

Design modification features vary in effectiveness and ease of application from boiler to boiler. Specific boiler designs and operating characteristics do play an important role in determining final NO_x emissions.

The concentrations of nitrogen oxides have been found to vary with different burner types, spacings, and locations. Cyclone burners are highly turbulent operations. This characteristic results in high-level emissions of nitrogen oxides in coal-fired units.

The amount of heat release in the burner zone, calculated by considering the total energy input into the furnace and the amount of energy lost to the surface area of the water walls near the burners, seem to have a direct effect on oxides concentration, especially during normal operation. One test showed a linear increase of nearly 3 times the NO_x , with 2.5 times the increase in heat release (1).

The difference in burner spacing has essentially no effect on nitrogen oxides concentrations in the boiler emissions, when boilers are at full load operation. However, at reduced loads, a close burner spacing would result in higher NO_x release, because the close burner spacing inhibits effective bulk gas recirculation into the primary combustion zone.

The distribution of air flow through the primary and secondary air ducts can also be used as an effective means to reduce NO_x emissions. Tangential firing furnaces, in which the furnace itself is the burner, exhibit lower peak flame temperatures and a corresponding reduction in nitrogen oxides emissions (as much as 50 - 60 percent compared to conventional units) (1).

The method of steam temperature control can have a definite effect on NO_x emissions. Three conventional techniques are employed: product gas recirculation, burner tilt, and the use of high excess air. Burner tilt and the use of high excess air both can increase NO_x emissions significantly. The logical choice for steam temperature control is flue gas recirculation, which has already been recommended as a viable means of NO_x control. Steam temperature control has a 33% removal efficiency (1).

Fluidized bed combustion offers efficient heat transfer rates and, hence, low average combustion bed temperatures. A major potential advantage is that both nitrogen and sulfur oxides can be controlled by the injection of limestone or dolomite. At present, only a few fluidized bed combustion boilers of commercial size have been built. The boilers are smaller and exhibit reduced fouling and corrosion problems. Efficiencies of fluidized boilers are slightly higher than conventional units with SO_2 removal systems. Potential disadvantages include gas distribution problems and loss of fluidization due to agglomerate formation (1).

5.6.1 Control Module Selection

The selection of the appropriate combustion modification technique is dependent on two main factors: the degree of NO_x reduction needed to meet government regulations; and, the choice of the unit that provides the most cost-effective alternative.

Engineering calculations for steam generation flue gases indicate that current NO_x emission standards would be exceeded by 1 percent if conventional steam generation equipment were used. Since the material balance was used for calculation, which is in essence an estimation, then, in an actual situation, conventional equipment might even satisfy existing regulations. In this case, it is not essential that the selected combustion modification technique possesses high NO_x reduction efficiencies (1).

The combined combustion modification techniques would be much more than adequate to achieve required emission levels. Being overdesigned, the combined techniques would not present a cost-effective alternative.

The use of low excess air provides adequate reduction efficiencies (25 percent); however, use of excess air alone would present problems with carbon monoxide and hydrocarbon emissions. For this reason, it is not judged a viable alternative.

Steam or water injection may reduce nitrogen oxides by at least 10 percent. Coupled with the fact that NO_x emissions from steam generation could be higher than estimated, the low reduction efficiency for the steam injection technique does not provide an adequate margin of safety.

Two-stage combustion and flue-gas recirculation are the two modification techniques that seem most promising with respect to meeting present day NO_x emission standards.

5.7 Fuel Cleaning

Sulfur dioxide and fly ash emissions can be greatly reduced in the steam generation if sulfur is removed from the coal prior to combustion. Fuel can be cleaned in two ways: by using a physical/chemical method or by routing it through the SRC process.

Physical separation processes are based on physical property differences of coal and pyrite (a mineral form of inorganic sulfur). Separation techniques include gravity, flotation, and electrical methods. Gravity methods make use of the differences in specific gravity between coal and impurities. Flotation separation methods rely on the difference in surface characteristics between coal and its impurities. Electrical methods use electrical (magnetic) forces to effect the separation and work because of the difference in magnetic susceptibility of coal and mineral matter. Commercial coal cleaning is currently performed using gravity methods in conjunction with froth flotation methods.

In general, physical methods can only separate out pyritic sulfur and hence have relatively low total sulfur removal efficiencies. Data from the U.S. Bureau of Mines indicates that the average sulfur content of coal (3.2 percent, based on 455 mines) could be reduced to 2.3 percent at 90 percent yield when crushed to 1-1/2 inch (3.8 cm) top size. Coal crushed to 3/8 inch (0.95) cm and 14 mesh would result in sulfur levels of 2.0 and 1.8 percent, respectively (16).

Based on federal regulations for SO_x emissions (1.2 pounds of SO_2 per million Btu's for coal-fired steam and power plants producing more than 250 million Btu/hour), and the amount and heating value of Illinois No. 6 seam coal, 15.6 tons per day (14.2 Mg/day) of SO_2 may be emitted to the atmosphere. Converting this value into the sulfur content of the coal needed for combustion yields a figure of 0.75 percent total sulfur. In other words, coal for steam generation must be cleaned to a sulfur content of 0.75 percent in order to meet SO_x emissions regulations with no additional pollution control techniques.

The chemical cleaning of coal involves treatment with reagents that convert impurities into a soluble form, which can then be removed by leaching. Chemical cleaning is most effective in dissolving discrete particles of pyritic sulfur, using acid, alkaline, and oxidation reduction methods. Physically cleaned coal is preferred as a feed to reduce costs of reagents. Generally, all processes were found to be effective toward the removal of pyritic sulfur, with a less pronounced effect on organo-sulfur compounds. One process using high temperature alkaline leaching was found to remove 99 percent pyritic sulfur and 70 percent organic sulfur (16).

A content of 5 percent total sulfur in Illinois No. 6 seam coal will contain approximately 2.92 percent organic sulfur, 1.81 percent pyritic sulfur, and 0.23 percent sulfate (17). Although the 5 percent figure is higher than the

average, it is within the range given for the sulfur content of Illinois No. 6 coal (18). Using this worst case approach and the removal efficiencies stated above, calculations indicate that chemical cleaning of coal would exceed the acceptable limit by 17 percent (.87 percent total sulfur). Using, for calculations purposes, the organic sulfur: total sulfur ratio stated above, the total sulfur content of a coal that could be cleaned to acceptable limits is 1.83 percent.

Table 30 presents total sulfur ranges in Illinois No. 6 seam coal by county. It can be easily seen that all of the counties have coals with averages above the acceptable value.

The above discussion suggests that advanced physical and chemical cleaning techniques are not a viable means of achieving SO_x emission standards without the use of some pollution control equipment.

Cleaned coal below the acceptable sulfur limit (0.75 percent) can be obtained by routing additional coal along with the process coal and using some SRC product as fuel for steam generation. Average values for solid SRC from October through December, 1976 were found to be 0.74 percent when a mixture of Kentucky No. 9 and 14 coals were used, having an average sulfur content of 3.9 percent over the three months. These figures represent an overall sulfur removal efficiency of 81 percent (19).

A worst case analysis using this removal efficiency and high range values for the sulfur content of No. 6 coals from White and Saline counties (3 percent) suggests an SRC sulfur content of 0.57 percent, well under the acceptable limit.

The major disadvantage of using SRC is that if SRC production is to remain at the same level, feed rates would have to be increased by roughly 6 percent in order to supply enough SRC for steam generation. If SRC is used for steam generation as an alternative approach to SO_2 control, a significant decrease in the overall thermal efficiency of the process can be expected.

5.8 Fugitive Emissions Control

Significant quantities of hydrocarbons and particulate matter are released to the atmosphere from storage tanks or piles and leaks from pipe and process vessel flanges.

TABLE 30. SULFUR CONTENT IN ILLINOIS NO. 6
SEAM COAL BY COUNTY (18)

County	Sulfur Content (percent)
LaSalle Grundy	3-5
Bureau Stark Henry Knox	3-5
Peoria Fulton	2-4
Sangamon Macoupin	3-5
Christian Montgomery Bond Madison	3-5
Vermillion	1-3
Clinton St. Clair	1-4
Madison Washington Randolph Perry	1-4
Jefferson Franklin Jackson	1-3
White Saline Williamson	1-3
Gallatin (Eagle Valley)	3-4

Emissions from storage tanks are due to several mechanisms that occur simultaneously as the tanks become warmer. The vapor within the tank expands and is released to the atmosphere, carrying hydrocarbons with it. The higher temperature also raises the equilibrium partial pressure of the hydrocarbons. In an effort to maintain equilibrium, more hydrocarbons are evaporated from the vapor phase. These evaporated hydrocarbons displace some of the vapor phase, causing further venting. Vent emissions from storage tanks can be controlled by the following practices:

- Eliminating the vent and building a tank which is strong enough to withstand the expected pressure
- Installation of a floating roof, thereby minimizing the vapor phase and allowing for changes in the volume of the stored hydrocarbons with temperature.
- Passing the vented hydrocarbons through a control unit such as an adsorber.

These control methods can not only recover valuable hydrocarbons for use or for sale. They also decrease the hazard associated with the handling and storage of these materials. Moreover, in many cases, they improve the working conditions for operating personnel.

Leaks from pipe systems and process vessel flanges will occur and present yet another source of fugitive emissions. A preventative maintenance and inspection program should be set up. In many cases, simply tightening pipe fittings and flanges will significantly reduce fugitive emissions. Guidelines for the prevention of fugitive emissions from piping systems and process vessels are listed below:

- Tighten all flanges
- Replace leak-prone threaded couplings with flanges or welded joints
- Gasket materials and pump seals should be corrosion resistant and compatible with the process fluid
- Double sealed or canned pumps should be employed
- Rupture disks should be installed under relief valves, to avoid leaks if a valve reseats improperly

- Preventative maintenance and inspection programs for above-ground and buried pipelines should be set up. These procedures are similar to those discussed under material spill control
- Double-pipeline systems for leak monitoring of buried pipelines should be considered
- The number of flanges, valves, and pumps should be minimized while provisions for prompt isolation of leaking sections and disposition of their contents must be planned with great care
- Prior to maintenance work or routine disassembly, material scavenging systems should be used, such as evacuating a process vessel using a compressor or purging the vessel with an inert gas.

Fugitive dusts from coal, sulfur, and SRC storage will generally be of a highly variable nature, depending on environmental conditions. Particle sizes are generally in the 1-100 micron range (20). For relatively small storage piles, such as sulfur storage, enclosures with particulate control apparatus must be weighed against outside storage piles using organic polymer coatings for dust control. For larger storage piles, such as the ROM coal pile, enclosure is infeasible.

5.9 Accidental Release Technology

5.9.1 Introduction

Accidental releases of pollutant materials from a coal conversion process are very similar to those encountered in a conventional petroleum refinery. Generally, there are two main categories of accidental releases: material spills, and gaseous venting during emergency operating conditions.

Spills are the result of leaks from tanks, pipes, valves, and fittings; ruptures in storage and process equipment; overfilling of tanks; and poor operation and maintenance processes in general. Material spills in coal conversion plants are mostly on land rather than on water. However, land spilled pollutants may find their way into the aquatic environment via groundwater contamination, so proper prevention, control, and cleanup procedures are essential to maintain environmental integrity.

Provisions must be made to handle huge quantities of process gases released by pressure release valves during emergency operating conditions. These emergency conditions occur due to compressor failures, loss of cooling water, vessel overpressure, power failures, fires, and other emergency conditions. It is common practice to tie all emergency relief valve outlets, along with any continuous waste gas streams, into a common header system that vents to a combustion flare.

Preventative and countermeasure techniques will be discussed with respect to material spills within the plant. A description of the types of flare systems that can be used for emergency venting will then be discussed.

5.9.2 Material Spill Prevention

There are a number of engineering practices which can be applied to a material spill prevention program and they are discussed below:

Leaks from storage tanks seem to be an ever present source of soil and groundwater contamination in oil refineries. Leaks develop when the tank bottom undergoes significant corrosion, and so many prevention practices involve the control of tank corrosion and include:

- Insure that structural materials are compatible with the material being stored.
- Assess structural integrity for conformance to code construction.
- Contained water promotes corrosion. Proper methods for draining water from tank bottoms should be employed. Figure 13 shows several commonly used methods for draining tank bottoms. It is also possible to develop automatic methods employing oil/water interface sensors such as density sensors, conductivity sensors, and dielectric constant sensors.
- Repair of leaks, corrosion, etc. must be prompt, no matter how minor. Leaks may be repaired by patching while the tank is in service, and numerous products are commercially available for patching.

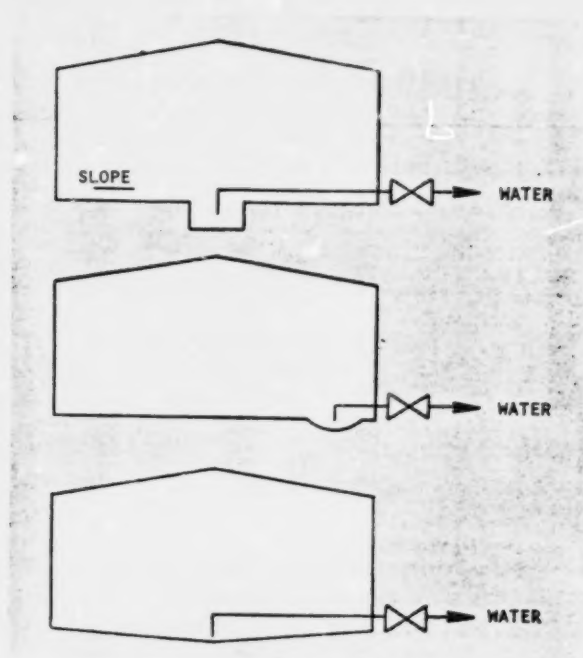


Figure 13. Tank Bottom Drainage Systems (21)

- Buried carbon steel tanks should be coated, wrapped, and lined. Depending on the nature of the soil, cathodic protection may be appropriate. Partially buried carbon steel tanks can set up galvanic corrosion and increase the rate of corrosion at the soil/air interface.
- Tanks should be examined periodically for evidence of external leakage (especially bottoms). This examination may consist of visual inspection, hydrostatic testing, and/or nondestructive shell thickness testing.

Shell thickness may be measured by ultrasonic analysis. Inspection records should be kept on a frequency basis that is consistent with the historical failure rate of tanks in the same service.

- Corroded tanks should be lined and coated with epoxy. This treatment fills small pits and crevices and prevents inside corrosion.

Normally, tanks are sandblasted to remove rust, dirt and scale which not only prevents product contamination but prepares the interior surface for epoxy coating. The coating needs to be selected for its compatibility with the material stored. X-ray analysis will locate pits and crevices.

- Deteriorated bottoms should be replaced with inverted cone-type bottoms. Figure 14 illustrates one technique for replacement of tank bottoms.
- Mobile storage tanks should be isolated from navigable waters by positioning and containment construction.

One of the most common sources of leaks and spills is the mobile storage tank such as the diesel fuel tank used for construction machinery. It is usually a simple task to dig a small pit or construct temporary dikes around the tank.

- The condition of foundation and supports of tanks should be assessed regularly.

In order to allow for adequate inspections and possible structural calculations, up-to-date drawings of the tank, foundation and structure must be maintained. Records of inspection should be kept for future reference.

- If a tank has internal heating coils, the condensate from these coils must be monitored for oil content.

Condensate oil content can be monitored visually or automatically. Figure 15 depicts the visual method using an inspection sump and the automatic method using a conductivity probe.

- Condensate from heating coils should be directed to oil/water separator or similar systems.
- Heating coils should be tested, maintained and replaced as needed.
- External heating systems are preferable to internal heating coils.

Typical external systems use plate coils which are placed on the outside of the tank near the bottom. Plate coils are bolted together and equipped with a band that can apply pressure to the contact surface between tank and coil for improved heat transfer.

- Internal condition of tank should be checked during every clean out maintenance.

Overfilling of storage tanks is a frequent cause of accidental spills. Preventative engineering techniques are listed below:

- Tanks should be carefully gauged before filling.
- High level alarms and pump shutoff devices should be in place.

Figure 16 shows a control system that will automatically stop a tank from overfilling. The signal generated by the level alarm can be used to close the inlet valve, stop the pump or both.

- Overflow pipes connecting to adjacent tanks should be in place.
- Automatic gauges and fail-safe devices must be tested periodically.
- A communication system between pump operation and tank gauging operation should be available.

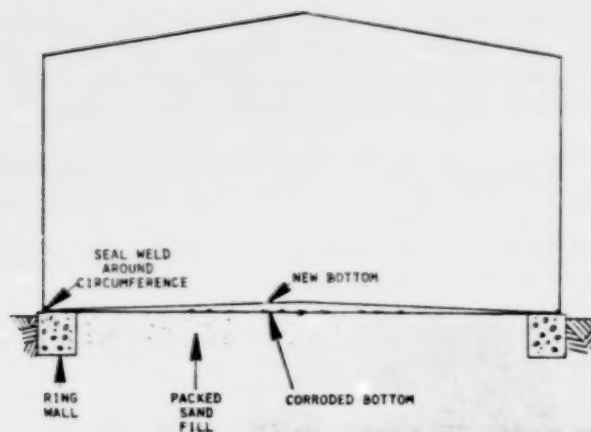


Figure 14. Tank Bottom Replacement (21)

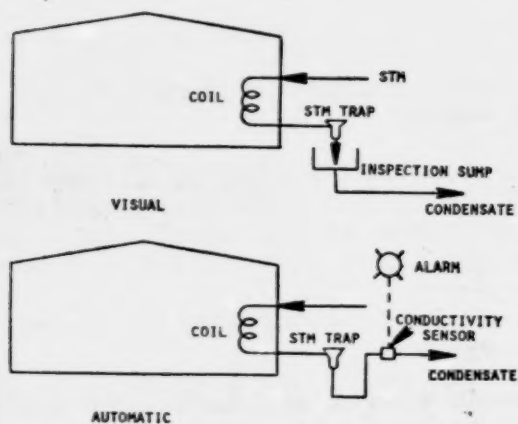


Figure 15. Internal Heating Coal Monitoring System (21)

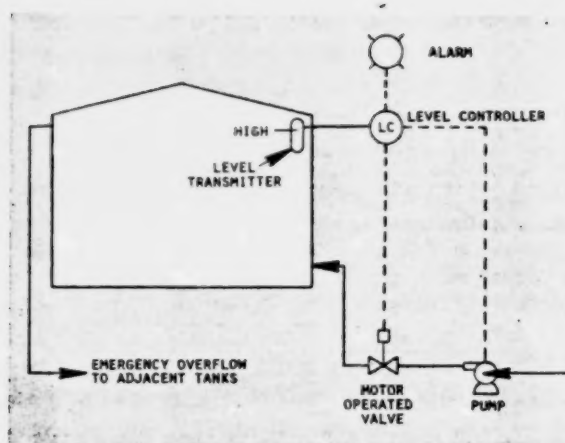


Figure 16. Tank Filling Control System (21)

A number of preventative techniques are available with respect to storage tank rupture and boilover:

- Insure structural integrity by code construction.
- Relief valves for excessive pressure and vacuum should be in place.

Many types of relief devices are possible. One of the most common is a pressure release manhole in the tank top which provides a large opening that can quickly relieve any pressure buildup.

- Safety relief provisions should be tested periodically.
- Adequate fire protection facilities must be available.

Even tank maintenance practices, such as tank cleaning and water drawoff, can generate material spillage and usually do. Pollution problems can be minimized by practicing the following guidelines.

- Water drawoff from crude storage should go to oil/water separator or oily sewer system.
- Water drawoff must be accomplished under controlled conditions with fail-safe devices, direct supervision, visual inspection, etc.
- Tank bottoms (sludge) during cleanout should be disposed of promptly.
- Temporary containment should be provided for bottom sludge.

Underground pipes, valves, and fittings have a high leak potential due to their susceptibility to corrosion. The following practices should be considered when installing and maintaining underground piping systems:

- Corrosion resistant pipe is preferable.
- Carbon steel pipe should be coated and wrapped (coal tar, asphalt, waxes, resins, fiberglass, asbestos, etc.).

- Cathodic protection system should be in place where surrounding soils contain organic or carbonaceous matter such as coke, cinders, coal, acid wastes, or other conditions. A soil resistivity survey may be in order.

There are companies that specialize in cathodic systems and they provide routine inspection services.

- Corrosion inhibitors should be used in piped products where internal corrosion is found and the inhibitor is compatible with the product.
- Marking lines should be obvious to prevent damage by third party excavators.
- Block valves should be located at strategic locations and periodically checked for operability.
- Insure that pipe meets specifications codes.
- Pressure drop fail-close devices should be in place. If the pressure in a line changes, then alarms can be activated and shutdown procedures initiated.
- Check valves to insure one-way flow should be in place where required.
- Rate of flow indicators should be in use.
- Pipe corridors should be inspected visually.
- Pipe lines should be hydrostatically tested periodically.
- Accoustical or magnetic testing equipment should be used to check for leaks.
- Condition of pipe should be checked and recorded when construction activities expose buried lines.
- Inventory of emergency repair equipment and fittings should be maintained.
- All abandoned lines should be removed, plugged or capped.

Above-ground piping systems also exhibit potential for leakage. Proper preventative techniques are as follows:

- Frequent inspection should be made.
- Protection from vehicle collision should be used.
- Abrasion around pipe supports should be controlled.
- Pressure drop fail-close devices should be in place.
- Block valves should be installed at strategic locations.
- Rate of flow indicators should be in place.
- A preventive maintenance program should be in force.
- Inventory of emergency repair equipment and fittings should be maintained.
- All abandoned lines should be removed, plugged or capped.

If a storage area spill does occur, the spill should be contained by a system of dikes, which should surround each storage tank. Dikes must be constructed to accommodate the maximum expected spill volume. Adequate freeboard allowance for rainfall retention is imperative. Dikes should be stabilized with an impervious coating such as asphalt, clay, or concrete, so that leak potential is minimized. Material of construction should be of an erosion-resistant nature. With respect to maintenance, the following guidelines should be established as practice.

- A program of dike inspection and maintenance should be in force.
- Vegetation on earth dikes should be controlled.
- Through-the-dike pipes no longer in use should be removed or plugged.
- Breaches made in dikes for maintenance purposes should be minimized. Build ramps for vehicle access.

Even if the diking system is adequate and well maintained, overflows or leaks may occur due to a problem with the containment area drainage valve. The following general practices should be employed:

- Positive shutoff valves should be used, instead of the flapper type.
- Full operational range (positive open and closed) should be assured.
- Valves should be locked in closed position.
- Visual indicator should be installed in the drainage system
- Easy access to drainage valves should be maintained.
- All weather operation should be assured, and no debris should be present in the valve area.

When draining dikes of oily water or stormwater, the following guidelines should be practiced:

- Retained water should be checked for oil contamination before release.
- Contaminated waters should go to oily water sewer (oil/water separator system).
- Storm waters (uncontaminated) can be routed to the stormwater drain.
- Records of drainage operations should be kept.

Miscellaneous practices that do not fit into any one category are listed below:

- A closed drainage system should be installed at sample locations.
- A maintenance and housekeeping program for drainage ditches and sewer inlets should be followed.
- Flooding of separator facilities must be precluded by retention, designing separator for stormwater flow and installing connected spare pumping capacity. Such designs may be governed by NPDES regulations.

- Procedures for minimizing concentrated oil dumps to the separator (sample coolers, bleed valves, etc.) must be followed.
- Absorbents are preferable to flushing to sewer during maintenance of piping and equipment.
- Security should be observed through limited access lighting, fencing, patrols, alarms, etc.
- Overpressure release valves should be installed on all process vessels to prevent plant losses and subsequent material spills.

5.9.3 Material Spill Countermeasures

A material spill contingency plan indicates procedures to be followed in the event that a spill occurs. There are four phases to a material spill contingency plan: detection, containment, recovery, and disposal.

5.9.3.1 Detection

Suitable detection methods must be employed, so that a material spill, no matter how minor, can be detected quickly. Although large spills usually receive immediate attention, this may not be true with smaller spills, whether continuous or intermittent. Frequently, small spills go unnoticed and unreported unless suitable detection methods are used. Some methods lie midway between prevention and detection.

Periodic inspections are essential. A complete survey can identify potential problem areas for periodic or continuous surveillance. Target areas should include heavily eroded stream banks where pipeline crossings occur, points of pipeline exposure, and any area where construction or excavation work is in progress. Generally, observation methods are marginally effective, and companion methods should be employed.

Oil sensitive probes can be located throughout a drainage system of a potential spill. When a spill occurs, feedback to a central control panel will immediately identify the location. Two types of probes are predominant: a conductivity type which depends on an induced change in the dielectric constant, and an ultrasonic type which is triggered by a change in viscosity. These units will signal the presence of oil in an area but not the source location of the spill.

Tagging may be used to identify both the source of a leak and the spread. This consists of adding coded materials to the stored or piped materials and then periodically analyzing drainage samples for their presence. The materials used must satisfy the following criteria:

- Physically and chemically stable
- Readily identifiable
- No effect on commercial uses of material
- Soluble and dispersible in the material, yet insoluble and nondispersible in water
- Inexpensive

Examples of tagging substances include halogenated aromatics, nitrous oxide, and radiochemicals. Tagging has not been widely used because of cost and complicating factors.

5.9.3.2 Containment

In the event that storage tanks are undiked or a material spill extends beyond the diked area, diversion systems, such as a catchment basin containing an oil trap, should be available. These should be designed to contain at least the amount of stored material plus sufficient excess capacity to insure complete interception. The primary separation of oil from the water should be accomplished as early in the system as possible so that the problem of handling large volumes of oil/water mix is minimized.

Should a spill take place outside the confines of a drainage system, a temporary dike or diversion trench must be constructed. The location would depend on expected direction and rate of flow. Information concerning these two factors, and in particular their relationship to temperature, should be included in a reaction plan.

Materials and equipment necessary for the construction of diversion or holding structures should be on hand. Barriers may be manufactured or improvised from a wide variety of materials including wood, plastics and metal. In some cases, locally available materials such as hay bales and sandbags will suffice. Aside from the requirement for mechanical strength, other considerations would include susceptibility to heat in the event of a fire and softening or cracking in the presence of some mineral oil components. Equipment that should be available includes standard excavation machinery and tools and commercially marketed booms.

If the spill should reach navigable water, there are a number of containment techniques that can be employed. They include booms, air curtains, and surface active agents. Two basic types of mechanical booms are available - curtain booms and fence booms. Curtain booms include a surface float that acts as a barrier on the surface and supports a subsurface curtain. The curtain is flexible and provides a barrier 1 to 2 feet (0.3-0.6 meters) below the surface. Weights may be attached for stabilization. Figure 17 is an example of this type. Fence booms differ only in that they have a rigid curtain or panel both below and above the surface. Flotation supports the "fence." These types are normally employed in deeper and rougher waters. Figure 18 is an example of this type.

Figure 19 shows one method of using a boom in an oil spill. Generally a boom will perform the following tasks:

- Compact widely scattered puddles of oil to facilitate skimming operations.
- Manipulate slicks away from sensitive areas or towards fixed removal installations.

With proper planning, the required booms should be readily available. In the event that such preparations have not been made, booms can be improvised through the use of materials such as hoses, bladders, tires, pipe and drums with attached planks.

Air curtains are produced by an air supply to perforated hoses and pipes. They may also serve as a containment apparatus under specific conditions. A schematic of an air barrier is shown in Figure 20.

Surface tension modifiers inhibit the spread of oil in water. When relatively small quantities of these chemicals are placed on the surface next to the floating oil, the oil is repulsed and tends to agglomerate. Application is simple; only a small amount need be used, applied as a coarse spray on the water at the edge of the spill. The effects last only a matter of hours, so cleanup plans should be implemented as soon as possible. As with any chemical, approval for the use of surface tension modifier must be obtained from appropriate governmental agencies.

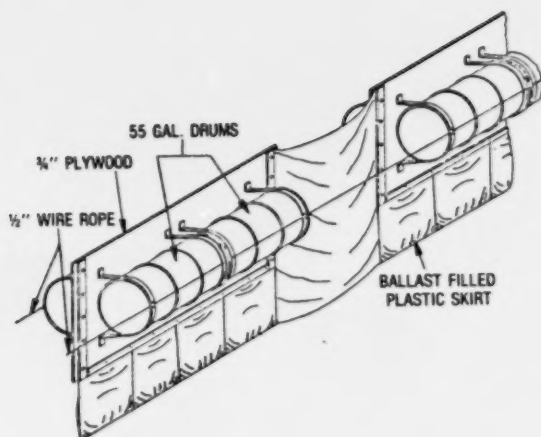


Figure 17. "Navy" Boom (Curtain Type) (22)

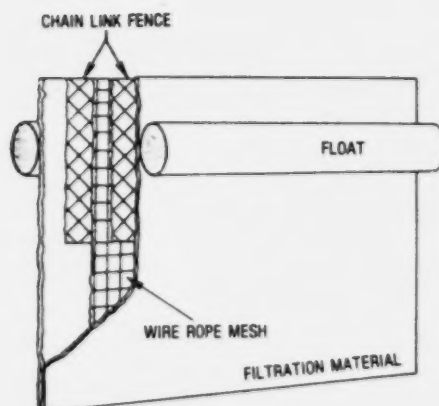


Figure 18. Kain Boom (Fence Type) (22)

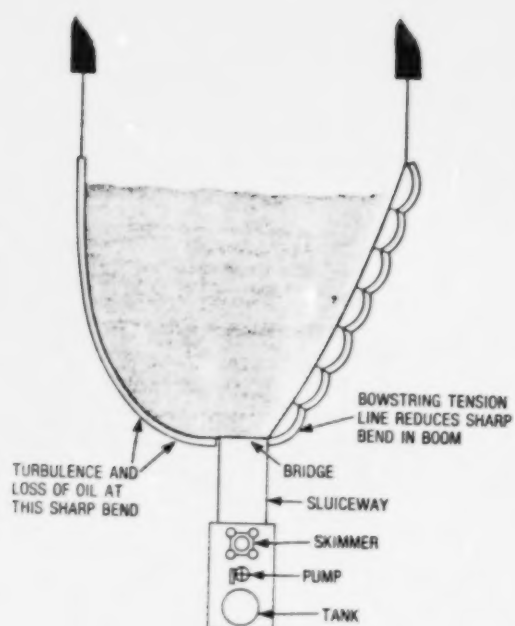


Figure 19. Boom/Skimmer Configuration for Oil Spill Cleanup (22)

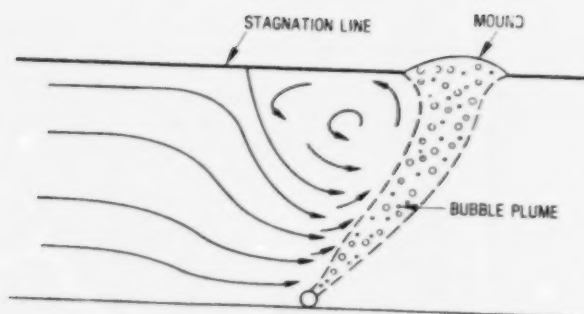


Figure 20. Circulation Pattern Upstream of an Air Barrier in a Current (22)

5.9.3.3

Recovery

Numerous harvesting devices and various removal techniques exist for handling harbor and inland spills. Sorbents are oil spill scavengers, cleanup agents which adsorb and/or absorb oil. Based on origin, sorbents may be divided into three classes:

- Natural products include those derived from vegetative sources such as straw, seaweed and sawdust; mineral sources such as clays, vermiculite and asbestos; and animal sources such as wool wastes, feathers and textile wastes.
- Modified natural products include expanded perlite, charcoal, silicone-coated sawdust and surfactant-treated asbestos.
- Synthetic products include a vast array of rubber, foamed plastics, and polymers. Table 31 details the effectiveness of various materials.

The requirements for a satisfactory sorbent include the following:

- Aids in handling and removing oil
- Minimizes spread of oil
- Is nontoxic
- Enhances performance of booms and other skimming devices

Removal of oil on water may require skimming. Skimmers may be purchased commercially or built for a particular application. Additionally, they may be floating, fixed, or mobile (mounted on boats, barges, trucks, etc.). The type of skimmer depends on its probable application. Of primary concern is its capacity in terms of total fluid handling volume, recovered oil volume, and pumping rate. These factors should be compatible with the expected utilization. Of secondary importance is the size, seaworthiness, speed, maneuverability, and other skimmer characteristics. Figure 21 shows the classes of skimmers.

Once the spill has been contained, it is usually removed and disposed of with a vacuum truck. One or more of these should be permanently assigned to the installation. If this is not the case, outside contractors must be identified and made familiar with the site facilities.

TABLE 31. SORBENTS' RELATIVE EFFECTIVENESS AND COSTS (22)

Type material	Pick-up ratio—weight oil pick up/weight absorbent	Unit cost, absorbent (\$/T absorbent)	\$ cost of absorbent for cleanup of 1,000-gal. oil spill
Ground pine bark, undried	0.9	6	27
Ground pine bark, dried	1.3	15	47
Ground pine bark	3		
Sawdust, dried	1.2 ^c	15	50
Industrial sawdust		56	
Reclaimed paper fibers, dried, surface treated	1.7	30	75
Fibrous, sawdust and other	3		
Porous peat moss	1.0		
Ground corn cobs	5	30	21
Straw	3–5 ^d	30	27
Chrome leather shavings	10	Indicated comparable to straw in cost.	
Asbestos, treated	4	500	440
Fibrous, perlite and other	5	416	290
Perlite, treated	2.5	230	320
Talcs, treated	2	70–120	120–210
Vermiculite, dried	2		
Fuller's earth		25	
Polyester plastic shavings	3.5–5.5	100	80
Nylon-polypropylene rayon	6–15		
Resin type	12	3,100	900
Polyurethane foam	70	20,000	1,000
Polyurethane foam	15	4,500	1,050
Polyurethane foam	70		
Polyurethane foam	40	2,260	195
Polyurethane foam	80	1,200	55

^c Another reference gives a ratio of 20

^d Other reports have indicated ratios of 20 and above

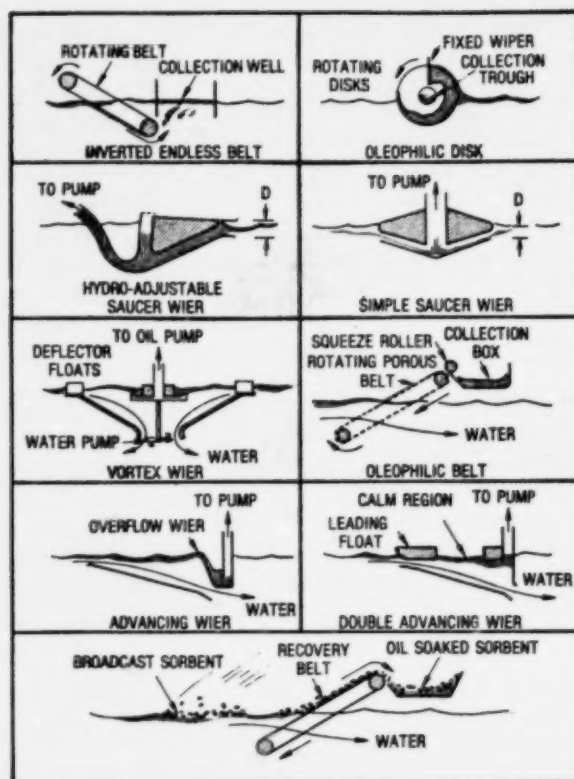


Figure 21. Classes of Skimmers (22)

An underground water supply may be endangered by a land spill. A considerable portion of the oil can be removed by excavating the contaminated soil before the oil has reached great depths. The extent or depth to which this would be economically feasible is a function of the type of oil as well as the underlying soil structure.

Oil from a land spill may reach the water table. If its viscosity is not too high, large amounts may be recovered by pumping. A well is drilled, centered in the spill, and screened at a depth no further than the oil/groundwater interface. In the pumping process, a cone of depression of the oil/water interface will be formed and will prevent oil from spreading further. At first the pump should extract oil exclusively; it should extract progressively more and more water. The amount of pumping is a function of recovered oil, spilled oil, and oil retained by the soil. Generally, pumping should stop when the oil/water ratio becomes less than 1 percent.

Spills eventually reach the plant drainage system; therefore, the site treatment facilities play a significant role in the oil removal process. Various types of separators are in use. Besides the classical API type, there are gravity plate separators and a host of multistage separators, some equipped with coalescence filters. In addition, there are other devices that employ proprietary methods ranging from ultrasonic treatment to polyelectrolyte injection.

Separation is ideally followed by physical-chemical treatment. This will incorporate some sequence of coagulation, flocculation, sedimentation and possibly air flotation. The remaining petroleum fraction can be removed by biological treatment. The activated sludge process is commonly used, often in conjunction with an aerated lagoon and a trickling filter. Following a dewatering step, the sludge may either be incinerated or hauled off for land-filling operations by a local contractor.

5.9.3.4 Disposal

Slop oil which has been recovered prior to reaching the drainage system or which has been separated in the initial step of the treatment system can be disposed of in several ways:

- Recycling recovered oil back into the plant process is the most common and the most economical. This is done by bleeding the slop oil into the feedstock over a period of time. Any impurities picked up during recovery of the spill are removed along with the usual bulk, sediment, and water. Any emulsions which have been formed can be broken using chemical agents and heat. As long as extensive "weathering" (evaporation of volatile components) has not significantly affected the fuel quality, this method can be used.
- Reclaiming recovered oil for other uses is a less desirable alternative. It is economically feasible only when the oil is not amenable to blending with the feedstock. This is normally done by an outside contractor equipped with appropriate re-refining facilities. These might include steam-
ing, filtering, and additive rebalancing. Such contractors frequently specialize in storage tank and sump cleanout operations as well.
- Burning is another method of final disposal of oil, particularly nonreclaimable sludges. Large amounts can efficiently be disposed of in this manner with the help of combustion agents or by blending with lighter grades of fuel such as kerosine. The mixture is then atomized and burned. This course of action requires careful control to obtain complete combustion to avoid air pollution.
- Dispersing. Dispersants are chemical agents which emulsify or solubilize oil in water. Their use is governed by Annex X of the National Contingency Plan. They should not be employed except when other methods are inadequate or infeasible.
- Sinking. As oil weathers and becomes more dense, there is a natural tendency of the residual fraction to sink. This phenomenon depends, of course, on the type of oil involved in the spill. Oil can be made to sink by application of a nucleus of high density material having an affinity for the oil (oleophilic property) and not having an affinity for water (hydrophobic property). The resulting mass of material then settles to the bottom.

Typical oil sinking agents include sand, fly ash, lime, stucco, cement, volcanic ash, chalk, crushed stone, and specially produced materials such as carbonized-silicanized-waxed sands. These are effective on thick, heavy, and weathered oil slicks.

The major problem in sinking oil is that the bonding of the agent with the oil must be nearly permanent. Many agents will release oil back into the environment after a period of time or as a result of agitation and turbulence. Microbial action on the oil-soaked particles also produces gaseous by-products which give the particle a tendency to float.

5.9.4 Flare Systems

There are three basic classifications of combustion flares, as follows:

- Elevated combustion flares
- Ground combustion flares
- Ground pits

5.9.4.1 Elevated Combustion Flares

Elevated combustion flares are the most commonly used. The combustion tip is usually 100-300 feet (33-100 meters) above grade, which drastically reduces the effects of heat radiation. Consequently, the flare can be located close to process units. In this way, the amount of vent piping and land requirements are minimized. The extra height also gives the added advantage of better dispersion of combustion products than with ground flares. Minimum height is determined with respect to radiation protection and is adjusted upward so that ground level contaminant concentrations will meet ambient air standards. The elevated flares, depending upon the method of achieving smokeless combustion, utilize air inspiration with steam or mechanical air blowing.

Steam injection into the flare tip can greatly reduce or even eliminate smoke generation. This reduction results from two effects. Steam has an inspiring effect and draws large quantities of air into the combustion zone. This supplies necessary oxygen for burning, provides intense

mixing, and has a solvent cooling effect which reduces cracking and polymerization. Steam also reacts with unreacted carbon particles to form carbon monoxide and hydrogen, as shown by the following equation:



The principal methods for injecting steam into flares involve the use of multiple jets, single nozzles, or a shroud. In the multiple jet design, waste gases are exhausted from the open end of the flare tip. A large header located around the periphery of the tip distributes steam to several jets. The jets are oriented so that their discharge covers the tip and creates turbulence and mixing of the waste gases with the surrounding air. Steam consumption is relatively low, 0.2-0.5 pounds (0.1-0.2 kg) of steam per kilogram of waste gas; however, this is balanced against the maintenance costs which are slightly higher than the single nozzle design. Tip construction utilizes corrosion-resistant alloy steel (1).

In single steam nozzle design, the steam line enters the flare and continues upward in the center until it terminates several inches below the top of the tip. As the steam exits the supply line, it expands to fill the inside of the flare tip and, in so doing, mixes with the waste gas. The turbulence created is not as great as with multiple jets. However, the system requires less maintenance due to its simple design (1).

In the shroud type design, the flare tip is surrounded by a metal skirt or shroud. This reduces some of the crosswind effects and forms a turbulent zone for premixing of the air and steam. Waste gas exits radially from the center portion of the tip and travels toward the shroud, causing intense mixing with the vent gas. Steam utilization is comparable with that of the multiple steam jet type (1).

In mechanical air blowing, blowers are utilized to provide air for smokeless combustion of small gas streams. For gas rates over 100,000 lb-moles/hr (45.4 Mg-moles/hr), the amount of air requires large equipment. Capital investment is not competitive with steam inspiration systems, if steam is available.

5.9.4.2 Ground Combustion Flares

Ground flares are built near grade level and seldom exceed 60 feet (20 meters) in height. Consequently, heat radiation effects require that flares be limited in size and located away from the process areas. This raises piping costs and eliminates them from consideration in plants with little available space and high-vent gas rates. Greatest application is for locations where elevated flares would be unsightly and complete smokeless operation is not required (1).

Ground flares have an important advantage in that water can be substituted for steam in many cases. Consequently, operating costs are greatly reduced. However, as the water requirement increases at high vent gas rates, it becomes increasingly difficult to obtain satisfactory combustion. Therefore, smokeless operation is limited to a maximum of 100,000 lb-moles/hr (45.4 Mg-moles/hr) gas flowrate (1).

A typical water injected ground flare is composed of three concentric stacks. The innermost stack contains the burner and water atomization nozzles. The second stack is slightly larger and serves to confine the tiny water droplets for effective mixing with the incoming air and the vent gases. The outermost stack merely directs the flame upward and protects against crosswinds. Slots are provided near the base of all three stacks to allow entrance of air by natural draft (1).

Ground flares can be designed to handle higher vent gas rates by using air inspirating venturi burners. Application is limited due to a pressure requirement of 1 to 4 psig (7,000-28,000 Pa) at the burner and 7 psig (48,000 Pa) backpressure (1).

Several burners are required to handle a wide range of vent gas rates. These auxiliary burners and their automatic control valves become a significant cost item. A major drawback of the system is that it cannot handle vent rates which substantially differ from the design basis.

5.9.4.3 Ground Pits

Burning pits are generally unacceptable except as a device to handle catastrophic emergency situations. They are excavated units with alloy steel burners along one or more sides. The walls are usually concrete or refractory-lined. Dense clouds of smoke are released during operation and the combustion products are not dispersed efficiently.

5.10 Regional Variations

5.10.1 Introduction

The Wabash River in White County, Illinois was selected as the site for the hypothetical SRC plant discussed in this report. This location was chosen because of the proximity of large deposits of a process compatible coal, Illinois #6, adequate water resources, and expressed interest by the State of Illinois in coal conversion technology. Also, since the area is already industrially developed, adequate auxiliary services, such as needed electricity and transportation, are available.

Location of the SRC complex in other regions of the continental United States can affect the quantity and composition of effluents, water consumption, pollution controls and process design. In the remainder of this section these regional influences are discussed.

5.10.2 Raw Coal

It is highly probable that SRC plants will be located near the source of the raw coal feed. The composition of this coal will affect the size and makeup of effluent streams, products, and by-products. Variations in these streams loadings will dictate the types of controls needed and the overall plant environmental impact.

For example, a low sulfur coal burned in the boiler could eliminate the need for SO_x stack gas scrubbers. A dissolver coal feed that has higher levels of trace metals, such as mercury or arsenic, could influence the methodology and location of solid waste disposal as well as increase air and water emissions. Consequently, more efficient control methods may be needed. A high sulfur coal will produce more sulfur as a by-product and require additional acid gas removal equipment.

The type of coal also influences the makeup and volume of emission in the coal preparation module. For example, different coals when pulverized produce varying quantities of coal with differing physical and chemical properties. This could influence the selection of control technologies.

5.10.3 Water

Limited supplies of water in certain regions of the country, such as the Southwest, can drastically influence process and control modules and even prevent locating some facilities.

This report emphasizes water conservation and a compromise between supply and need may be necessary. Recycling streams may be necessary, especially in extremely dry parts of the country. Reduction of cooling water requirements via recycling and increased usage of air-cooled heat exchangers can significantly affect total water usage. In water-short areas, wet air pollution control systems, such as particulate and SO₂ scrubbers may be impractical. Alternative control technologies, such as cyclone, baghouses, or coal desulfurization, may be necessary. The quantity of raw water used in boilers or cooling towers will influence the type of raw water treatment, the frequency of blowdown, and the type of corrosion inhibitors used. These parameters will affect the overall influent to the waste treatment.

5.10.4 Climate

Coal pile runoff flows into process drains. The amount of precipitation at the plant site will directly affect the volume of coal pile runoff. Acidic rainwater, such as that found in the eastern United States, will promote leaching of trace metals from the coal. The wastewater treatment plant must be designed to accommodate the runoff due to regionally typical storms.

In arid regions, such as the Southwest, the coal pile may have to be moistened more frequently to reduce fugitive particulate emissions. However, wetting the pile may, in turn, increase coal pile runoff as well as use precious water.

5.10.5 Auxiliary Systems

Expected high concentrations of trace metals, sulfates, and organic and inorganic compounds in solid waste produced at the plant can pose a serious pollution problem. A landfill capable of properly handling the waste should be located in a reasonable proximity to the plant. Inability to locate or develop a proper landfill site meeting local and federal regulations could prevent siting the facility.

Adequate transportation for receiving raw material and shipping products must be readily accessible to the plant. Increased traffic, air and water pollution in the area could restrict locating the facility.

In this study, all electricity has been assumed to be produced off-site. However, an electrical generating unit could be integrated into the plant operations if purchasable electricity were unavailable. Generating power in-house would cause additional emissions. Overall increases in air (SO_x, particulates, NO_x), solids (ash), and water (cooling tower and boiler blowdown, thermal, etc.) discharges would be included.

5.10.6 Local Regulations

If the facility is located in an area with differing environmental regulations from those of White County, Illinois, allowable quantities of pollutant discharges also may differ. These regulations could be either more stringent or more liberal, depending upon the particular location. Obviously, different regulations would affect both process and control technologies or possibly prevent siting altogether.

6.0 Detailed Definition of Basic System

6.1 Introduction

The previous sections of this Standards of Practice Manual have been presented as summary information, describing the basic SRC system, pollution control options and costs, and existing and proposed State and Federal regulations. The preceding section, although seemingly an in-depth view of pollution control, is in actuality a summary of the available control options and their design criteria, with respect to expected emissions from a coal liquefaction facility. The sections mentioned above should provide the engineer with a general knowledge about the basic process, its emissions, available control technology, and standards that may apply to a commercial SRC facility.

The purpose of this section is to provide the engineer with detailed knowledge of the SRC system, its emissions, and the most economically feasible and environmentally acceptable control options. This is accomplished by furnishing a system description and material balance for a 50,000 bbl/day (7,950 m³/day) theoretical SRC-II commercial facility. The SRC-II system is described with respect to modules which carry out specific functions within the overall system. Material balances are provided for each module so that process and waste streams may be viewed in a concise manner.

Based on material balance data, process data, and engineering calculations, the waste streams will be further characterized to include volumetric flow rates, temperature, pressure, grain loading, BOD, suspended solids concentrations, and other parameters that may not be apparent in the material balance and general process description.

Next, applicable control options are matched to specific waste streams using design criteria presented in Section 5.

Cost and performance data have been developed from published literature and vendor information. The cost and performance data for recommended control modules is presented in tabular form for each waste stream, so that treatment alternatives can be readily compared.

Alternatives for wastewater treatment, sludge disposal and flares cannot be included in this modular approach, since they accommodate combined waste streams from several process modules. They are therefore discussed under separate headings.

6.2 Coal Preparation Module

6.2.1 Module Description

There are a number of different coal preparation processes that may be suitable for use in an SRC commercial facility. All of them produce a cleaned, dried, and ground coal product; however, different processes may result in different quantities of waste streams. It is expected that the general nature of discharges from such facilities will be similar.

Figure 22 presents a schematic flow diagram of a typical coal preparation facility. Only the major pieces of equipment are shown. The module receives run-of-mine coal and processes it into feed sized to minus 1/8 inch (0.3 cm), suitable for slurry preparation (23). The module can be divided into a number of process steps, i.e., receiving, reclaiming and crushing, storing, drying and pulverizing, and slurry mixing.

Run-of-mine (ROM) coal may be received either by rail or truck. It has been calculated that about 31,552 TPD (28,681 Mg/day) of ROM coal would be needed for a 20,000 TPD (18,182 Mg/day) SRC facility with steam generation and gasification. If coal is received by rail, a railroad hopper car dumps each carload into a hopper below rail level. ROM coal also can be received from mine trucks, where it will also be unloaded into a receiving hopper. A vibratory feeder transfers the coal from the hopper to a belt conveyor, which in turn transfers it to a rail-mounted slewing stacker. The slewing stacker may move along the length of a belt, forming a stockpile on one or both sides of the belt. The stockpile has been designed to hold 94,560 tons (85,964 Mg) of ROM coal. The stockpiling system will gather up to 1,300 tons (1,182 Mg) of ROM coal per hour. This stockpile does not represent total storage capacity of the coal preparation facility, since minus 3" (7.6 cm) coal (after reclaiming and crushing) is also stored.

Coal is reclaimed from the ROM stockpile by a bucket-wheel which feeds the coal going to a transverse conveyor to one or two belt conveyors. A transverse conveyor takes the coal from either of the belt conveyors and delivers it to a receiving hopper. The reclaiming system will handle up to 1,300 tons (1,182 Mg) of coal per hour. Coal is discharged to a 60-inch (1.5 m) reciprocating plate feeder onto a 48-inch (1.2 m) belt driven conveyor, fitted with a magnet to remove tramp iron. The coal is conveyed to a 3-inch (7.6 cm) scalping screen, which separates out oversize coal (3-inch [7.6 cm], plus) and allows broken coal (7.6 cm, minus)

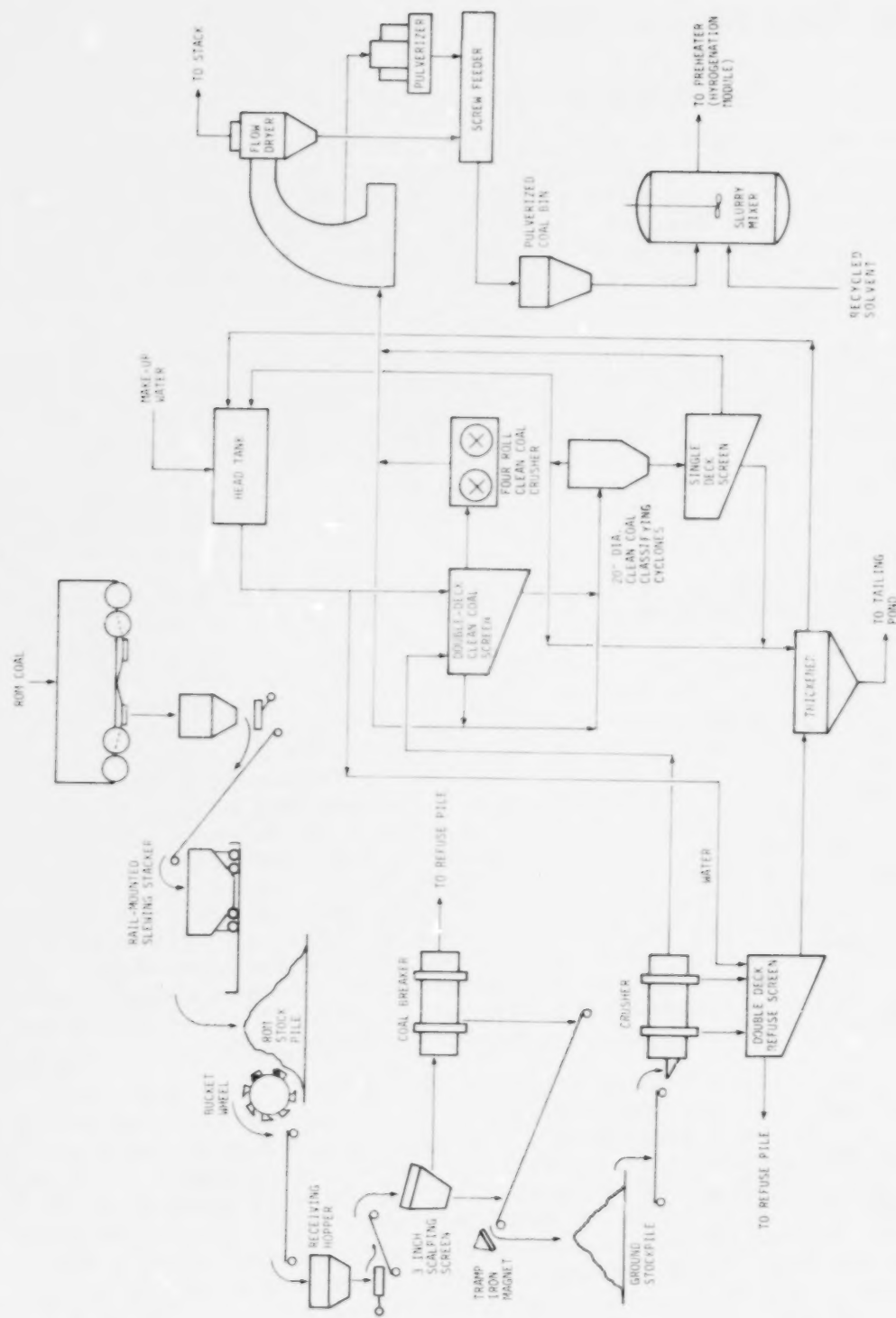


Figure 22. Process Schematic - Coal Preparation Module

to pass through. The oversize coal is charged to a rotary coal breaker, where it is crushed to less than 7.6 cm. Oversize refuse present in ROM coal is separated in the coal breaker. The broken coal is placed on a 1.2 meter belt conveyor, where it is combined with the undersize coal from the scalping screens and discharged to a 10,000 ton (9,091 Mg) storage pile.

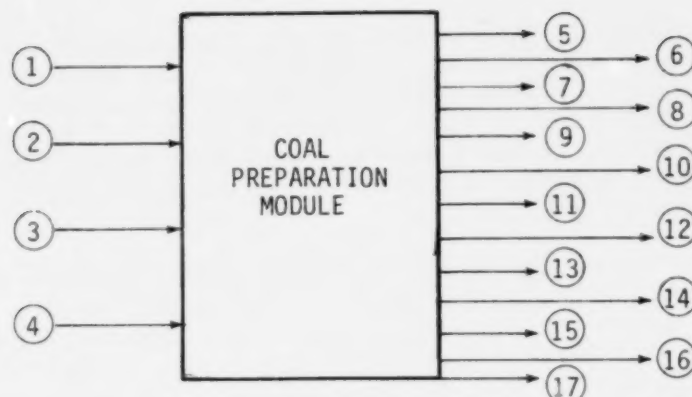
Two storage piles are incorporated into the coal preparation module, the ROM stockpile and the broken coal storage pile, representing a total storage capacity of approximately 104,560 tons (95,055 Mg) of coal. A polymer coating may be applied to each storage pile to minimize oxidation. Most rainfall coming in contact with coated storage piles will run off while only a small percentage will infiltrate. Assuming a storage pile is conical 25 ft. (7.6 m) tall, its total area has been calculated to be approximately eight acres ($3.3 \times 10^4 \text{ m}^2$).

Coal is withdrawn from the minus 7.6 cm, ground coal storage pile and conveyed to the washing plant for cleaning and reduction. A series of jigs, screens, centrifuges, cyclones, and roll crushers clean the coal and reduce it to minus 1-1/4 inch (3.1 cm). Oversize refuse is separated from the coal stream and returned to the mine for disposal. Wet fine refuse is pumped to settling ponds. The clean minus 3.1 cm coal is then dried in a flow dryer and reduced to minus 1/8-inch (0.3 cm) in pulverizers. The pulverized coal is suitable for slurry feed mixing.

The dried, pulverized coal is transferred by conveyor to the coal/solvent tank, in which 20,000 tons (18,182 Mg) of coal and 40,000 tons (36,364 Mg) of unfiltered solvent are mixed per day. The slurry is then pumped to the preheater.

6.2.2 Process and Waste Streams

Process and waste streams present within the coal preparation module are designated with respect to the unit operations within the module, as shown in the block flow diagram, Figure 23. Waste streams in the block flow diagram are described below. Components in selected waste streams are quantified in Table 32.



<u>STREAM</u>	<u>QUANTITY * (TPD)</u>	<u>(Mg/DAY)</u>
1. ROM Coal (5% Moisture)	31552	28684
2. Recycled process solvent	40000	36364
3. Air for coal drying (70% R.H.)	32810	29827
4. Makeup water	4837	4397
5. Fuel gas and air	3961	3601
6. Moisture from environment	1909	1735
7. Coal dust	24	22
8. Tramp iron and refuse	1645	1495
9. Refuse from cleaning processes	6839	6217
10. Coal pile runoff	74	67
11. Thickner underflow (35% solids)	3432	3120
12. Dry coal to gasification (2% moisture)	1531	1392
13. Dry coal to steam generation (2% moisture)	1041	940
14. Coal/solvent slurry to hydrogenation	60408	54916
15. Dryer stack gas	32842	29856
16. Gland water	NOT QUANTIFIABLE	
17. Flue gas	3961	3601

*Streams may not balance due to roundoff.

Figure 23. Coal Preparation Module Process and Waste Streams

TABLE 32. PROCESS AND WASTE STREAM CONSTITUENTS
IN COAL PREPARATION MODULE

	(TPD)	Quantity* (Mg/day)
(5) Fuel gas and Air		
Fuel gas		
CH ₄	107.3	97.5
C ₂ H ₆	67.4	61.3
N ₂	1.6	1.5
CO	27.4	24.9
CO ₂	0.3	0.3
Air	3757.4	3415.8
(15) Dryer Stack Gas		
Air	32810.0	29827.3
Water	3281.0	2982.7
Particulates	32.0	29.1
(17) Flue Gas		
N ₂	2981.0	2710.0
CO ₂	552.6	502.4
O ₂	178.3	162.1
H ₂ O	249.6	226.9

* Streams may not balance due to roundoff

- Dust from Coal Receiving, Storage, Reclaiming and Crushing - Coal dust is generated during transfer of coal from shipping to receiving bins and during storage (wind action), conveying, stacking, reclaiming, and crushing operations. Dust is composed of coal particles, typically from 1 to 100 microns in size, with a composition similar to that of the parent coal. Proximate and ultimate analyses of Illinois No. 6 seam coal can be found in Table 33, an ash analysis is presented in Table 34, and a trace element analysis is given in Table 35. Data in Table 35 suggest that coal dust will contain significant concentrations of the trace elements titanium, magnesium, boron, fluorine, zinc, and barium. Dust generated from the above operations has been estimated to amount to approximately 24 tons/day (22 Mg/day) for a 20,000 ton/day (18,182 Mg) plant (1). This amount has been estimated to be divided equally among the three processes.

- Coal Pile Runoff - Coal pile runoff results from rainfall and infiltration waters that come into contact with the stored coal. The resulting leachate may contain oxidation products of metallic sulfides; it is frequently acidic, with relatively high concentrations of suspended and dissolved solids, sulfate, iron, calcium, and other coal constituents. The quantity and concentration of coal pile runoff water generated is dependent on the type of coal used; the history of the pile; and the rate, duration, frequency, and pH of precipitation. An analysis of runoff from two coal piles is presented in Table 36. No information was available specific to Illinois No. 6 coal.

Assuming a stormwater runoff coefficient of 0.7, the mass flow rate of coal pile runoff waters has been calculated (74 TPD [67 Mg/day]), based on the average annual rainfall for Illinois (42.5 in [108 cm]) and the area of coal storage ($3.3 \times 10^4 \text{ m}^2$) (24,25).

- Refuse from Reclaiming and Crushing - Refuse from the reclaiming and crushing modules is composed chiefly of tramp iron, slate, coal, and "bone." These materials are naturally present in the coal seam. Particle size is greater than 3 inches (7.6 cm).

TABLE 33. RUN OF MINE (ROM) ILLINOIS
NO. 6 COAL ANALYSIS (23)

Proximate Analysis (weight percent):

Moisture	2.70
Ash	7.13
Volatile matter	38.47
Fixed carbon	51.70
Heating value	12,821 Btu/lb (3×10^7 J/kg)

Ultimate Analysis (weight percent):

Carbon	70.75
Hydrogen	4.69
Nitrogen	1.07
Sulfur	3.38
Oxygen	10.28

TABLE 34. AVERAGE ASH ANALYSIS OF ILLINOIS
NO. 6 COAL (26)

Component	Percent of Ash
SiO ₂	44.4
Al ₂ O ₃	21.0
Fe ₂ O ₃	22.1
TiO ₂	1.1
P ₂ O ₅	0.1
CaO	5.2
MgO	1.0
Na ₂ O	0.5
K ₂ O	2.0
SO ₃	1.7

TABLE 35. TRACE ELEMENT COMPOSITION OF
ILLINOIS NO. 6 COAL SAMPLES (27)

Element	ppm
Aluminum	13500
Antimony	0.98
Arsenic	5.9
Barium	111
Beryllium	1.5
Boron	135
Bromine	15
Cadmium	<4
Calcium	7690
Cerium	13
Cesium	1.2
Chlorine	1600
Chromium	20
Cobalt	6.6
Copper	13
Dysprosium	1.0
Europium	0.25
Fluorine	63
Gallium	3.1
Germanium	<5.6
Hafnium	0.52
Indium	0.14
Iodine	1.9
Iron	18600
Lanthanum	7
Lead	27
Lutetium	0.08
Magnesium	510
Manganese	53
Mercury	0.18
Molybdenum	9.2
Nickel	22
Phosphorus	45
Potassium	1700
Rubidium	16
Samarium	1.2
Scandium	2.6
Selenium	2.2
Silicon	26800
Silver	0.03
Sodium	660
Strontium	36
Tantalum	0.16
Terbium	0.17
Thallium	0.67
Thorium	2.2

TABLE 35. TRACE ELEMENT COMPOSITION OF
ILLINOIS NO. 6 COAL SAMPLES (27)

(Continued)

Element	ppm
Tin	4.7
Titanium	700
Tungsten	0.7
Uranium	1.6
Vanadium	33
Ytterbium	0.54
Zinc	420
Zirconium	52

TABLE 36. CHARACTERISTICS OF COAL
PILE DRAINAGE (28)

Constituents	Concentration mg/l (unless otherwise indicated)	
	Plant J	Plant L
Acidity (total), as CaCO ₃	1,700	270
Calcium	240	350
Chemical Oxygen Demand	9	--
Chloride	0	--
Conductance, umho/cm	2,400	2,100
Dissolved Solids (total)	3,200	1,500
Hardness, as CaCO ₃	600	980
Magnesium	1.2	0.023
pH, unit	2.9	2.9
Potassium	--	--
Silicon (dissolved)	91	--
Sodium	--	4.1
Sulfate	2,600	--
Suspended Solids (total)	550	810
Turbidity, JTU	300	--
Aluminum	190	--
Arsenic	0.01	0.009
Barium	--	0.1
Beryllium	--	0.01
Cadmium	0.001	0.006
Chromium	0.005	0.005
Copper	0.56	0.18
Iron	510	830
Lead	0.01	0.023
Manganese	27	110
Mercury	0.0002	0.027
Nickel	1.7	0.32
Selenium	0.03	0.003
Titanium	1	--
Zinc	3.7	1.0

- o Refuse from Pulverizing and Drying - This refuse stream is generated after screening with the double deck refuse screen. The stream contains slate, "bone," coal, and water added during screening. Both refuse streams are stockpiled before removal to the mine for burial.
- o Thickener Underflow - Wastewater generated from a number of processes in the coal preparation module is routed to a thickener where particulates are removed and clarified water is recycled. The underflow stream has a flow of 3,432 TPD (3,120 Mg/day) with a suspended solids loading of 1,201 TPD (1,092 Mg/day) which corresponds to a concentration of 35% suspended solids. The wastewater is expected to contain a substantial quantity of coal-derived organic constituents prior to wastewater treatment.
- o Gland Water - Gland water is generated from leaks in the piping system; hence, it has not been quantified. It may contain substantial concentrations of particulate and organic matter. Gland water may be collected in a sump and pumped to treatment.
- o Gaseous Emission from Drying - This waste stream has been calculated to carry 3,281 TPD (2,983 Mg/day) of moisture and 32 TPD (29 Mg/day) of particulates for a 20,000 TPD (18,182 Mg/day) plant. A significant concentration of coal-derived organics are also expected to be present in this stream. Gas from fuel combustion is composed of carbon dioxide, water, carbon monoxide, nitrogen, oxygen, and unreacted hydrocarbons.

6.2.3 Control Equipment Specification and Cost Estimation

Waste streams that emanate from processes in the coal preparation module are summarized in Table 37, along with applicable control technology. The following presents a detailed characterization of the waste streams control and options and capital and operating costs of sized units.

TABLE 37. WASTE STREAMS FROM COAL PREPARATION MODULE

Source Unit Operation	Nature of Waste	Quantity		Applicable Control Measures
		TPD	(Mg/day)	
Coal Receiving	Coal Dust	8	7	Cyclone & baghouse High eff. cyclones Wet scrubbers
Storage	Coal Dust	8	7	Polymer coating Enclosed storage
Storage	Runoff	74	67	Tailings pond
Reclaiming, Crushing & Pulverizing	Coal Dust	8	7	Cyclone & baghouse High eff. cyclones Wet scrubbers
Dryer	Stack Gas	32842	29856	Baghouse, wet- scrubber
Water Recycle System	Thickener underflow	3432	3120	Tailings pond
Screening	Tramp iron and refuse	8484	7713	Mine burial

Coal dust from the coal receiving area is generated by transferring coal from the receiving hopper to the conveyor belt and to the slewing stacker (see Figure 22). The dust-laden air is at atmospheric pressure; therefore, collection hoods and a duct system must be designed for dust transport to a particulate removal unit. The flow rate of the dust-laden air will depend on the combined flow rate of the collection hoods. Exhaust requirements for conveyor belts traveling greater than 200 feet per minute (61.0 m/min) suggest that collection hoods be designed for a flow rate of 500 ft³/min/ft. (0.6 m³/sec/m) of belt width (29). If 1.2 m belt conveyors are used, then the collection hood must have a minimum flow rate of 2,000 cfm (0.9 m³/sec) for efficient dust collection. It is recommended that collection hoods be installed at transfer points and enclosed as much as possible (29). Since there are two transfer points in the receiving area conveyor system, two collection hoods are required, each with a flow rate of 2,000 cfm (0.9 m³/sec). Based on a dust release rate of 8 TPD (7 Mg/day) in coal receiving and a combined flow rate of 4,000 cfm (1.8 m³/sec), a grain loading of 19.5 grains/cu. ft. (35.0 mg/m³) has been calculated.

Here, as in the receiving area, three particulate removal systems can be considered as treatment alternatives: cyclone and baghouse, high efficiency cyclones or multicyclones, or a wet scrubber system. Cost data can be found in Table 38 along with efficiencies and expected emissions based on waste stream characteristics, as calculated. Again, the cyclones and baghouse system is suggested above the others.

Refuse and tramp iron from crushing operations are disposed of by burial in the mine. Hauling costs will depend on distance from the facility to the mine. It is assumed that this distance will be less than fifty miles. If collection trucks are used, hauling costs will range from \$1-\$6 per ton (\$0.9-5.4/Mg) of waste (14). A daily refuse and tramp iron load of 8,483.5 TPD (7,712 Mg/day) for the 20,000 TPD (18,182 Mg/day) facility generates a hauling cost of \$8,500-\$50,900 per day or \$2.5-15.3 million annually.

Two major waste streams emanate from the drying and pulverizing section of the coal preparation module, i.e., dryer stack gas and thickener underflow. Thermal dryers are the largest single source of air pollution in the coal preparation module. Particulate emissions from thermal dryers range from 15-25 lbs/ton (8-10 g/Mg) of coal processed (12). Flow dryers, which have a cyclone collector built within the unit, can be expected to have considerably lower emissions. If cyclone efficiency is assumed to be 90%, particulate emissions from flow dryers will range from 1.5 to 2.5 lbs/ton (0.8-1.0 g/Mg) of processed coal. Based on a coal rate of 31,700 TPD (28,818 Mg/day), this value represents a particulate loading of 32 TPD (29 Mg/day).

Calculations for the dryer stack gas volume and grain loading were based on the following criteria:

Exit gas temperature	=	60°C
Exit gas pressure	=	1 atmosphere
Relative humidity at 60°C	=	70%
Heat capacity of air	=	0.25 cal/g°C

The dryer stack gas flow rate was calculated to be 32,810 TPD (29,827 Mg/day) with a volumetric flow rate of 0.8 MCF/minute (377 m³/sec) at 60°C. This value equals 240 m³/sec at standard conditions, based on a relative humidity of 70% at 60°C. Grain loading was calculated to be 0.4 grains per actual cubic foot (0.65 mg/m³) or 0.6 grains/dscf (1.2 mg/m³) with a particle size range of 0.1-20 microns.

TABLE 38. TREATMENT ALTERNATIVES FOR
DUST STREAM FROM COAL RECEIVING (31,32,33)

Basis: 4,000 cfm ($1.8 \text{ m}^3/\text{sec}$) with a grain loading of 19.5 grains per
ft³ (35.0 mg/m^3) (34,689 ppm)

Treatment	Cost		Efficiency	Emission After Treatment	Secondary Waste ³
	Capital ¹ (\$1,000)	Annual Operating ²			
Cyclone & Baghouse Total	4.5 10.5 15.0	not available	99.9%	35 ppm	dust
High-Efficiency Cyclone	4.5	not available	99+%	347 ppm	dust
Wet Scrubber	7.75	\$1600/yr ⁴	98.5%	520 ppm ⁵	wastewater

¹Includes cost of equipment and installation.

²Includes cost of fuel, utilities, and maintenance.

³Secondary wastes are wastes generated by the operating pollution control unit.

⁴With recirculation.

⁵By weight

There are three particulate removal systems that can be considered as treatment alternatives: cyclones and baghouse, high efficiency cyclone system, or wet scrubber system. Electrostatic precipitation is not viable because of the high explosion potential. Advantages and disadvantages of each system have been previously discussed. Table 38 presents the results of calculations for the three alternate systems. Data are given on capital and operating costs, efficiencies, and expected emissions based on the characteristics of the waste stream. The cyclone and baghouse system, although expensive, gives the best removal efficiencies and is most compatible with the highly variable dust streams.

Two waste streams emanate from coal storage area, i.e. fugitive coal dust and coal pile runoff. Methods for fugitive dust control are limited. The stock pile may be sprayed with an organic polymer coating or the coal may be stored in an enclosed storage bunker. The ROM coal pile of 94,560 tons (85,964 Mg) is much too large for enclosure, therefore polymer spraying is the only feasible means of control. Material costs are approximately \$300/acre ($7\text{¢}/\text{m}^2$) of stockpile (30). The material is sprayed, and using a hydromulcher, operating costs range from \$600-1000/day (30). Material costs for the ROM coal pile ($3.3 \times 10^4 \text{ m}^2$) would be \$2,400 per application. An application every three days would result in a material cost of about \$240,000 per year with operating costs of \$180,000-300,000/year.

The broken coal pile is considerably smaller than the ROM stockpile, having a capacity of about 10,000 tons (9,091 Mg) and a storage area of only $2.0 \times 10^4 \text{ m}^2$. A comparative cost analysis of polymer coating versus enclosed storage is shown in Table 39. Operating costs for the polymer coating of the 10,000 ton (9,091 Mg) storage pile would be overwhelmed by the operating costs for coating the ROM storage pile. However, a rough estimate of operating costs can be made by using the six-tenths factor on storage area ratio of both piles. The scaled down operating cost for coating the smaller pile would range from \$126-211/day, using the six-tenths factor. Annual operating costs would average \$12,600-\$21,100, based on an application every three days (100 days for a 300 day stream year). Enclosed storage can no longer be considered a feasible alternative, due to the excessive capital cost (\$6-8 million) as compared to the cost of polymer coating.

TABLE 39. COSTS OF CONTROL ALTERNATIVES FOR FUGITIVE DUST (30,34)

Basis: 10,000 Ton (9,091 Mg) Broken Coal Storage Pile

	Operating Cost (Annual)	Capital Cost
Polymer Coating	\$12,600-21,000	\$18,000
Enclosed Storage		\$6-8 million

Coal pile runoff calculations were based on the 67 Mg/day average annual rainfall data for Illinois. This value corresponds to a hydraulic flow of 17,700 gallons/day (67 m³/day). Coal pile runoff waters will be combined with thickener underflow and routed to the tailings pond. Data with respect to contaminants in coal pile runoff water are in Table 40.

Coal dust generated from reclaiming and crushing operations has been estimated to be roughly 8 TPD (7 Mg/day). There is a potential dust problem during reclaiming by bucket wheel. The problem has been controlled in other coal preparation plants by water spray during operation. It was therefore assumed that the bucket wheel reclaiming system does not contribute significantly to the total dust load. The 7 Mg/day dust load comes from four 1.2 m conveyor belts in the reclaiming and crushing section. Coal breakers and crushers are water sprayed and do not generate significant quantities of dust. Just as in the receiving area, collection hoods must be installed. Their design flow depends on the width of the conveyor belt, and they will be installed at the two transfer points of each belt. In order to minimize the cost of ducting, it is suggested that separate removal units be installed for each conveyor. Each particulate control unit will handle the combined flow rate of two collection hoods (1.8 m³/sec). If it is assumed that each conveyor belt will generate 2 TPD (1.8 Mg/day) of coal dust, the grain loading to each unit will be 4.86 grains/cu ft (6.5 mg/m³).

TABLE 40. TREATMENT ALTERNATIVES FOR DUST STREAMS
FROM COAL RECLAIMING AND CRUSHING (31,32,33)

Basis: Four units, each handling 4,000 cfm ($1.8 \text{ m}^3/\text{sec}$) with a grain loading of 4.86 grains/ft³ (6.5 mg/m^3) (8,646 ppm)

Treatment	Cost		Efficiency	Emission After Treatment	Secondary ³ Waste
	Capital ¹ (\$1000)	Operating ² (Annual)			
Cyclone & Baghouse	4,500 10,500	not available	99.9%	8.6 ppm	Dust
Per Unit	15,000				
Total	60,000				
High-Efficiency Cyclone					
Per Unit	4,500	not available	99+%	86.5 ppm	Dust
Total	18,000				
Wet Scrubber					
Per Unit	6,750	\$1600 ⁴	98.5%	129.7 ppm	Wastewater
Total	27,000	\$6400			

¹Includes installation.

²Fuel, utilities, and maintenance.

³Wastes generated by operating pollution control unit.

⁴With recirculation.

The promulgated federal standards of performance for new and modified coal preparation plants require that emissions from coal dryers may not exceed 0.031 grains/dscf (0.05 mg/m³) and 20 percent opacity. In order to meet these standards, particulate removal efficiencies must be above 95.2%. Cyclones have removal efficiencies of less than 90% for particles less than 20 microns. Therefore, they are not considered to be feasible treatment alternatives. Applicable control technologies include the use of a bag filter system or a wet scrubber unit. Characteristics of each unit have been discussed in the Control/Disposal Practices section. Because of excessive water use in wet scrubbers, baghouses are more feasible.

Table 41 presents capital and operating costs, efficiencies, and expected emissions from the two control alternatives.

TABLE 41. CONTROL ALTERNATIVES FOR
STACK GAS FROM COAL DRYING (32,33)

Basis: 0.8 MACFM (377 m³/sec) at 140°F (60°C) with a grain loading of 0.4 gr/acf (0.65 mg/m³) (712 ppm)

Treatment	Cost		Efficiency	Emission After Treatment	Secondary Waste
	Capital (\$1000)	Operating			
Baghouse	1000	Not available	99.9%	0.7 ppm	Dust
Wet scrubber	380	\$28,000	98.5%	10.7 ppm	Wastewater

Thickener underflow has been previously quantified in the process material balance (3,432 TPD [3,120 Mg/day]). It is routed to a tailings pond along with coal pile runoff. The combined flow of the two streams has been calculated to be approximately 0.8 MGPD (3,179 m³/day) with coal pile runoff comprising only about 2 percent of the total hydraulic flow.

A number of factors which must be considered in the design of a tailings pond include the following (35):

- (1) Adequate detention time must be provided (4-6 hours).
- (2) Sludge storage should be provided. This volume should not be included in the calculation of the volume required for adequate detention (estimate 1 month storage volume)
- (3) Adequate volume should be provided to store the 10 year storm (estimate 5.1 inches or 12.9 cm).
- (4) Approximately 2 feet (0.6 m) of freeboard should be provided in the pond.

In addition to the above criteria, the cost per acre of the basin is important. There is a wide range of depths which fits the above, but the cost of basins (\$/ acre) has been observed to increase with depth. Approximately 15 feet (4.5 m) is the maximum depth which should be considered. Table 42 lists two alternative basin designs based on cost. A liner is included in the cost analysis because of the nature of the wastes discharged to the pond.

TABLE 42. TAILINGS POND (4)

	Costs (\$1000)	
	Alternative I (1 acre, 13.5 ft deep) (4047 m ² , 4.1 m deep)	Alternative II (2 acres, 8 ft deep) (8094.0 m ² , 2.4 m deep)
Pond	27.0	11.6
Hand Dress Slopes	0.419	0.360
Anchor Ditches	0.298	0.440
Liner (PVC)	5.68	10.350
Liner Installation	0.67	1.22
Contingency	3.4	5.99
Total	37.42	29.97

6.3 Hydrogenation Module

6.3.1 Module Description

Hydrogenation is a process whereby the coal molecule, under high temperature and pressure, is broken down into a number of active free radicals which can combine with hydrogen to produce a mixture of hydrocarbon products. When the pressure ranges from 200 to 2000 psig (1.4-14.0 MPa), no catalyst is needed in this process. A flow diagram of the hydrogenation process is shown in Figure 24 (23).

In the hydrogenation process, the resultant coal/slurry mixture from the coal preparation area is first injected with hydrogen gas. The hydrogen gas is a mixture of recycle hydrogen and synthesis gas from the hydrogen production module, and has a total hydrogen content of 97% by volume. The gas/slurry stream is pumped to a dissolver preheater elevating the pressure to about 1700 psig (11.9 MPa). The preheater increases the temperature to approximately 850°F (454°C). The preheater is fired by fuel gas (23).

The heated mixture is then introduced into a dissolver where the coal is depolymerized and hydrogenated. The solvent is hydrocracked to form hydrocarbons of lower molecular weight, ranging from light oil to methane; organic sulfur is hydrogenated to form hydrogen sulfide. The temperature and pressure in the dissolver are about 850°F (454°C) and 1700 psig (11.7 MPa), respectively (23).

The resultant product stream contains gases, liquids, and solids. It is removed from the dissolver reactor and transferred to a series of vessels to separate various products. The estimated composition of the product stream is given in Table 43.

6.3.2 Process and Waste Streams

Module input and output streams are shown in Figure 25. Stream compositions are given in Table 44. Preheater fuel gas is the only continuous waste stream discharged from the hydrogenation module. Fuel gas and flue gas compositions also are given in Table 44. There is also a possibility of hydrocarbon vapor leakage from the reactors and transient spills. Leaks and spills would be controlled by proper maintenance procedures and spill contingency plans as outlined in section 5.9.2.

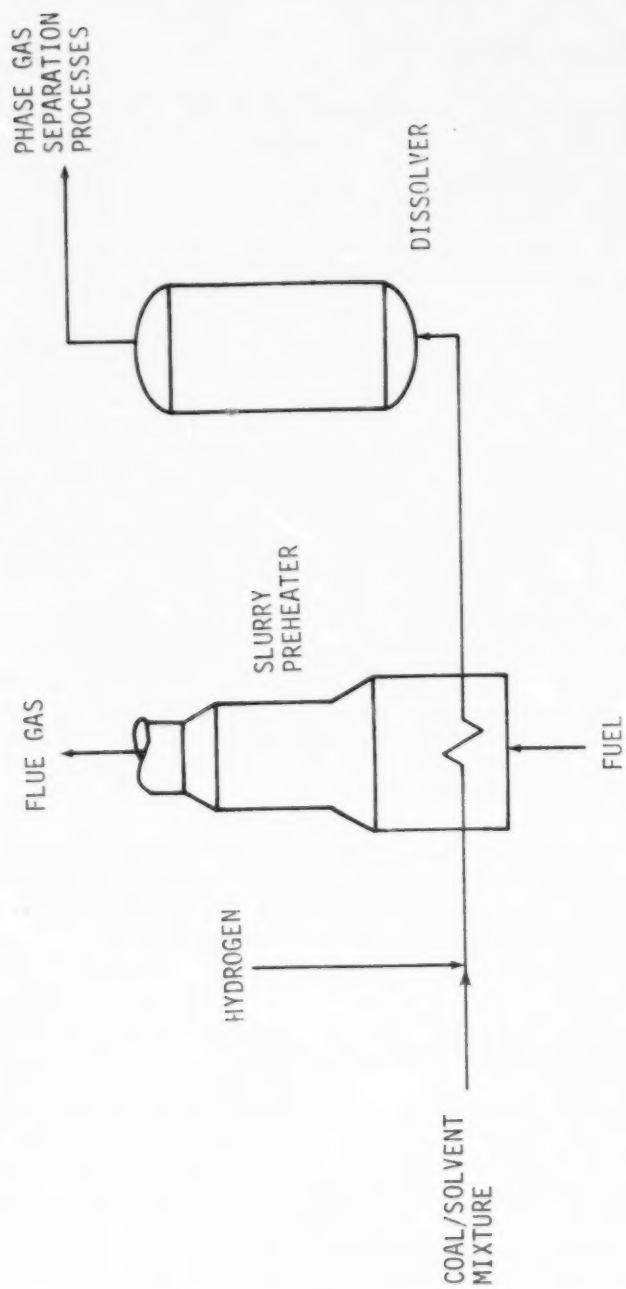
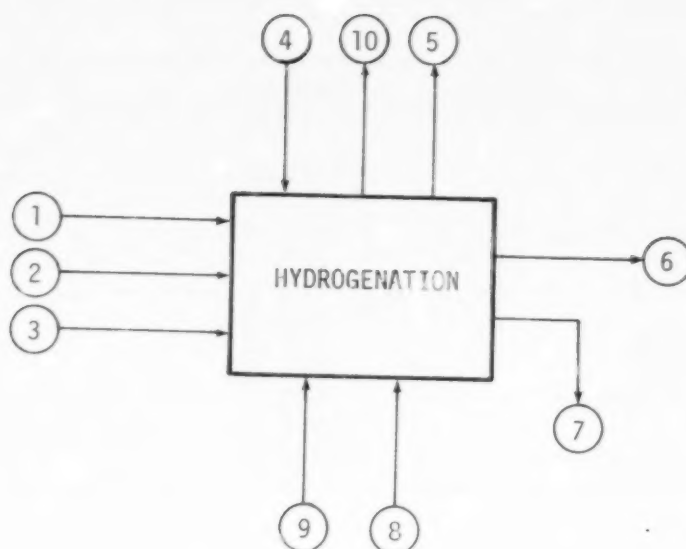


Figure 24. Hydrogenation Module Flow Diagram

TABLE 43. HYDROGENATION REACTOR EFFLUENT

Compound	Quantity (TPD)	(Mg/day)
Liquid Product	49142.0	44674.5
Residue and Ash	3062.0	2783.6
Light and Heavy Oils	3491.8	3174.4
Hydrogen Sulfide	469.0	426.4
Ammonia	60.0	54.5
Nitrogen	18.5	16.8
Carbon Monoxide	397.3	361.2
Carbon Dioxide	288.8	262.6
Unconsumed Hydrogen	563.7	512.5
Water	3346.6	3042.4
Gaseous Hydrocarbons	3545.9	3223.5



	QUANTITY*	
	(TPD)	(Mg/day)
1. Coal/solvent slurry	66408	54916
2. Water	2652	2411
3. Synthesis gas from hydrogen production	734	667
4. Hydrogen from gas purification	592	538
5. Vapor discharge	NOT QUANTIFIABLE	
6. Product (gas/liquid/solid)	64386	58532
7. Accidental material spills	NOT QUANTIFIABLE	
8. Fuel gas	760	691
9. Air	13998	12725
10. Flue gas	14758	13416

*Streams may not balance due to roundoff.

Figure 25. Hydrogenation Module Process and Waste Streams

TABLE 44. HYDROGENATION MODULE STREAM COMPOSITIONS

STREAM	QUANTITY*	
	(TPD)	(Mg/day)
1. Coal/Slurry Solvent		
Coal	20408.0	18552.7
Solvent	40000.0	36363.6
3 Synthesis gas		
H ₂	321.0	291.8
CO	321.0	291.8
CO ₂	73.1	66.5
N ₂	18.5	16.8
H ₂ S	.03	.03
8 Fuel Gas		
N ₂	6.1	5.5
CO	102.1	92.8
CO ₂	1.0	0.9
CH ₄	399.9	363.5
C ₂ H ₆	251.0	228.1
10 Flue Gas		
N ₂	11105.3	10095.8
O ₂	664.1	603.7
CO ₂	2058.7	1871.6
H ₂ O	929.8	845.2

*Streams may not balance due to roundoff

6.3.3. Control Equipment Specification and Cost Estimation

The main environmental discharge from the hydrogenation module is flue gas from the preheater. This amounts to approximately 14,758 TPD (13416 Mg/day) for a fuel gas usage of 760 TPD (691 Mg/day). No controls are applied to this waste stream prior to discharge since it contains only nitrogen, oxygen, carbon dioxide, and water.

Hydrocarbon vapors from pressure release valves will be generated and will be routed to a flare system (See Flare system). Accidental material spills generated from such operations as reactor cleanouts can be prevented by following the practices outlined in Section 5.9.2.

6.4 Phase (Gas) Separation Module

6.4.1 Module Description

The phase (gas) separation module separates hydrocarbon vapors and other gaseous products from the dissolver effluent slurry stream and directs the solids/liquid portion of the coal slurry to other processing areas. There are five processes within this module: high pressure separation, condensate separation, intermediate flashing, intermediate pressure condensate separation, and low pressure condensate separation. A module flow diagram is shown in Figure 26.

The processed coal/solvent slurry from the dissolver is first introduced into a high pressure separator where the hot vapor is separated from the slurry under dissolver outlet pressure (i.e., 1650 to 1700 psig [11.4-11.7 MPa]). The temperature is maintained at about 550°F (292°C). Since the influent slurry is usually around 850°F (454°C), an air cooled heat exchanger may be used ahead of the separator to aid in reducing the slurry temperature. The separated gases are then directed through a water cooled condenser to a high pressure condensate separation vessel along with hydrogen sulfide, nitrogen, ammonia, carbon monoxide and carbon dioxide. The uncondensed vapors are sent to gas purification and the condensate is directed to a low pressure condensate separator. The remaining solid/liquid slurry from the high pressure separator is directed to an intermediate flash vessel (36).

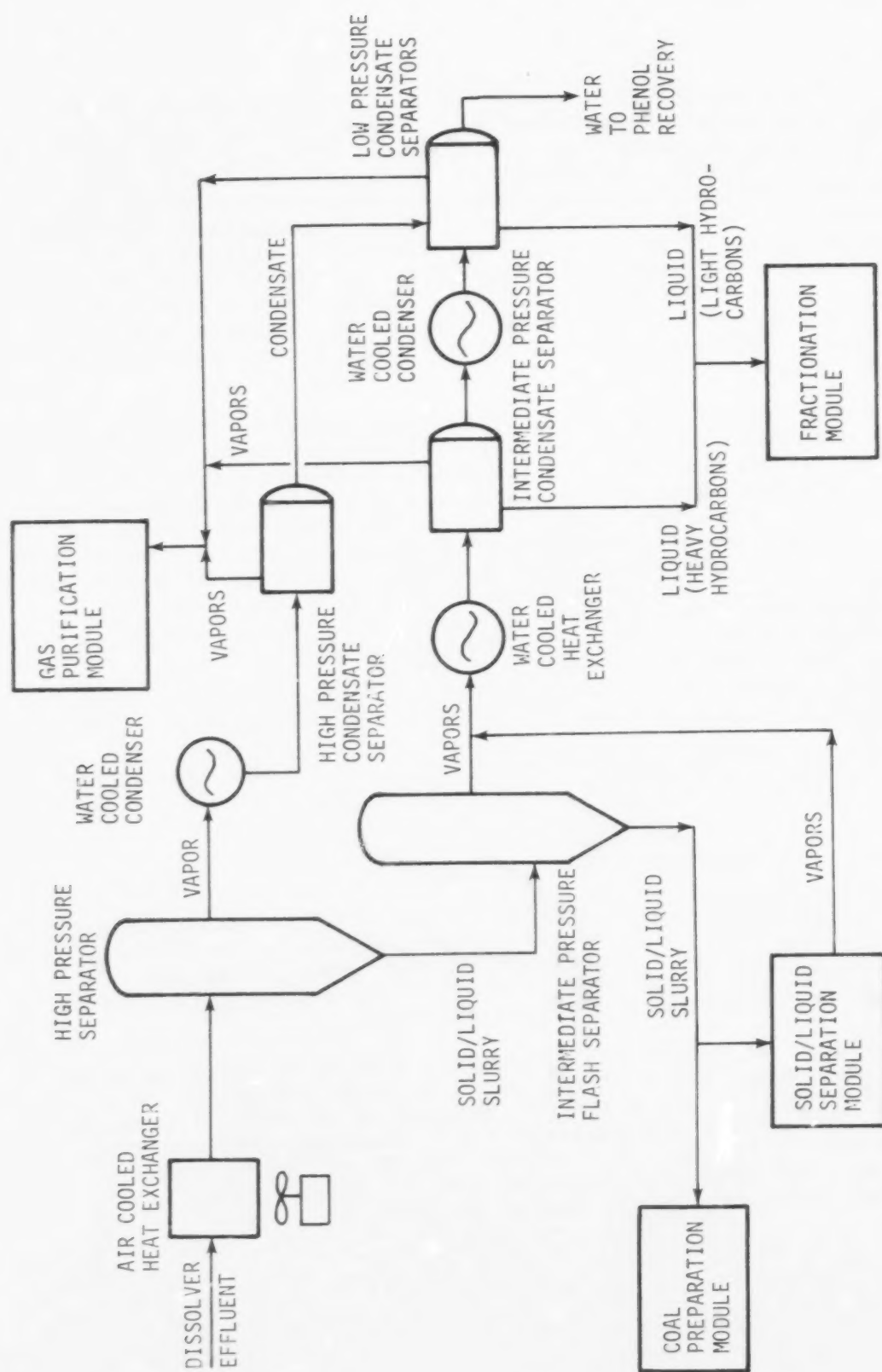


Figure 26. Phase (Gas) Separation Module

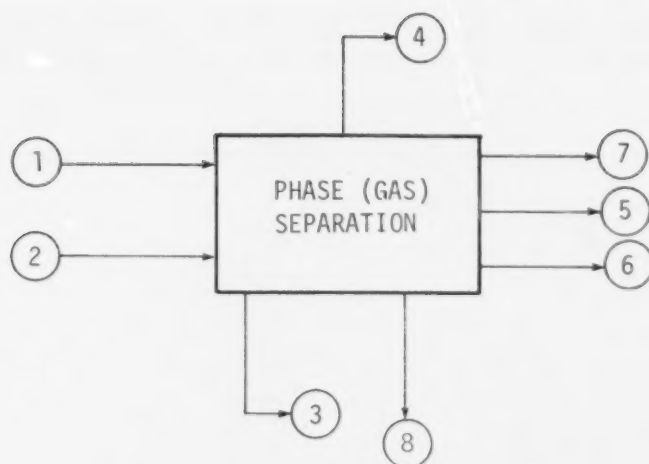
The solids/liquid slurry from the high pressure flash separator enters an intermediate flashing vessel where the pressure is decreased to approximately 500 psig (3.4 MPa) under a constant temperature of 550°F (292°C) (36). The reduced pressure vaporizes numerous hydrocarbons which are discharged to the intermediate pressure condensate separator. The remaining slurry consisting mostly of original solvent, dissolved coal, and undissolved coal solids is split into two streams. The majority of the slurry flow (40,000 TPD [36,363 Mg/day]) is recycled back to the coal preparation module. The remaining slurry is routed to the solids separation module.

The vapors from the intermediate pressure flash separator are directed through a water cooled condenser prior to entering the intermediate pressure condensate separator. Heavier-than-water hydrocarbons are separated from water and lighter hydrocarbons and routed to the fractionation module. Uncondensed gases are directed to the gas purification module. The water and light hydrocarbon stream is combined with the vapor stream from the filter feed flash unit (solids separation module) and gas-liquid stream flows through another condenser. The condensed mixture is charged to a low pressure condensate separator in which the hydrocarbon, water, and gaseous phases are separated. The light hydrocarbons are routed to the fractionation module. Sour water is directed to by-product recovery processes. The uncondensable gases flow to the gas purification module for the removal of hydrogen sulfide and carbon dioxide.

6.4.2 Process and Waste Streams

Three continuous process streams are discharged from the phase gas separation area: product slurry to filtration, condensate to fractionation, and acid gas to gas purification. Sour water is a by-product stream which is directed to ammonia and phenol recovery.

Since the phase gas separation module is operated as a closed system, there are no waste streams discharged on a regular basis. Two potential sources of material discharge from this module are fugitive vapor discharge and discharge from accidental spills. A flow diagram depicting process streams and potential waste streams is given in Figure 27. Stream compositions are listed in Table 45.



<u>STREAM</u>	<u>QUANTITY*</u>	
	<u>(TPD)</u>	<u>(Mg/day)</u>
1. Influent product stream (dissolved effluent)	64386	58533
2. Flash gas stream from solids/liquid separation	1037	943
3. Slurry to solid/liquid separation	13241	12037
4. Gases to gas purification	5279	4799
5. Light and heavy oils to fractionation	3454	3140
6. Sour water	3449	3135
7. Vapor discharge	NOT QUANTIFIABLE	
8. Accidental material spills	NOT QUANTIFIABLE	
9. Recycle slurry to coal preparation area	40,000	36,364

*Streams may not balance due to roundoff.

Figure 27. Phase (GAS) Separation Module Process and Waste Streams

TABLE 45. PHASE (GAS) SEPARATION MODULE STREAM COMPOSITIONS

STREAM	QUANTITY*	
	TPD	(Mg/day)
2 Flash Gas		
H ₂ S	11.1	10.1
H ₂	45.8	41.6
CO	63.7	57.9
CO ₂	9.6	8.7
H ₂ O	1.0	0.9
NH ₃	7.5	6.8
Hydrocarbons	898.0	816.4
4 Gases to Purification		
H ₂	568.7	517.0
H ₂ S	424.1	385.5
N ₂	18.5	16.8
H ₂ O	40.0	36.4
NH ₃	0.2	0.2
CO	397.3	361.2
CO ₂	288.8	262.5
Hydrocarbons	3545.9	3223.5
6 Sour Water		
H ₂ O	3306.6	3006.0
Phenol	37.8	34.4
NH ₃	59.8	54.4
H ₂ S	44.9	40.8

*Streams may not balance due to roundoff.

6.4.3 Control Equipment Specification and Cost Estimation

Two potential intermittent discharges from the phase (gas) separation module are vapor release due to pressure build-up or emergency operating conditions, and accidental material spills. These discharges are attenuated by proper flaring and by following proper maintenance and spill contingency procedures, as outlined in section 5.9.2. Flare system specification and cost information is given in section 6.14.

6.5 Solids Separation Module

6.5.1 Module Description

The slurry product stream from the phase (gas) separation module consists of the dissolved coal solution, light hydrocarbons, and undissolved solids. Undissolved solids consist mainly of unreacted coal, char, and mineral matter. The slurry may also contain some dissolved H_2S . The solids separation module separates the undissolved solids from the dissolved coal solution. The position of this step in the overall system varies somewhat, according to what design is used. The original Parson's design has solids separation before the fractionation module (23). The SRC II pilot plant design incorporates solids separation by vacuum flashing after fractionation (37). The latest SRC design by Ralph M. Parsons Company also has the solids separation step following fractionation (38). This report was based on the original Parsons' design and therefore has the solids separation module before fractionation. In future revisions of this report, the solids separation module will be described as following fractionation, if this arrangement is found to be satisfactory. The environmental discharges resulting from both system arrangements are expected to be similar.

Besides alternate system arrangements, a number of alternatives are available for the solids separation itself, e.g., rotary precoat filtration, vacuum flashing, centrifugation, and solvent de-ashing. Studies have indicated that efficient separation is difficult, due to the size distribution of suspended particles (1-300 microns) and the high viscosity of the dissolved coal solution (39).

Although rotary precoat filtration has been used somewhat successfully in SRC production, it is considered expensive and has frequent scheduled downtime. Centrifugation of the slurry has had limited success. Vacuum flashing has been used successfully in the SRC-II process. The solvent de-ashing technique has been under bench-scale investigation for some time; however, no pilot plant scale data are available in the literature.

Data from rotary precoat filters have been used in the material balance, since material balances have been obtained only from design studies using this separation technique. Material balances will be somewhat similar when using other solids separation methods.

A flow diagram of a hypothetical solids/liquid separation module is shown in Figure 28. In the process, the hydrogenated coal slurry from phase (gas) separation is charged to a feed flash vessel. The vapor released is let down through a control valve to condensate separation in the phase (gas) separation module. The liquid effluent from the feed flash vessel flows to the solids separation unit, i.e., a filter, vacuum flash, centrifuge, or solvent de-asher. The solids stream is sent to a secondary vacuum flash or a dryer to concentrate the residue, depending on the method of solids separation. Since vacuum flashing is used in this design, secondary flashing is required rather than drying. Recovered solvent is routed to the fractionation module. Most of the residue stream from the secondary flash is routed to the solidification module. Any additional recovered solvent is combined with the main solvent stream and routed to fractionation.

6.5.2 Process and Waste Streams

Process and waste streams entering and leaving the solids separation module are shown in Figure 29. Stream constituents are quantified in Table 46. There are essentially no wastewater streams in the solids separation area other than the drainage of accidental spills during maintenance operations.

The only continuous atmospheric waste stream is the flue gases from residue drying. Vapor discharges from pressure relief valves will be routed to flare. Accidental material spills and fugitive vapors will be attenuated by following preventative procedures and spill contingency plans.

The liquid residue stream from solids separation is routed to the solidification module for cooling into a solid product.

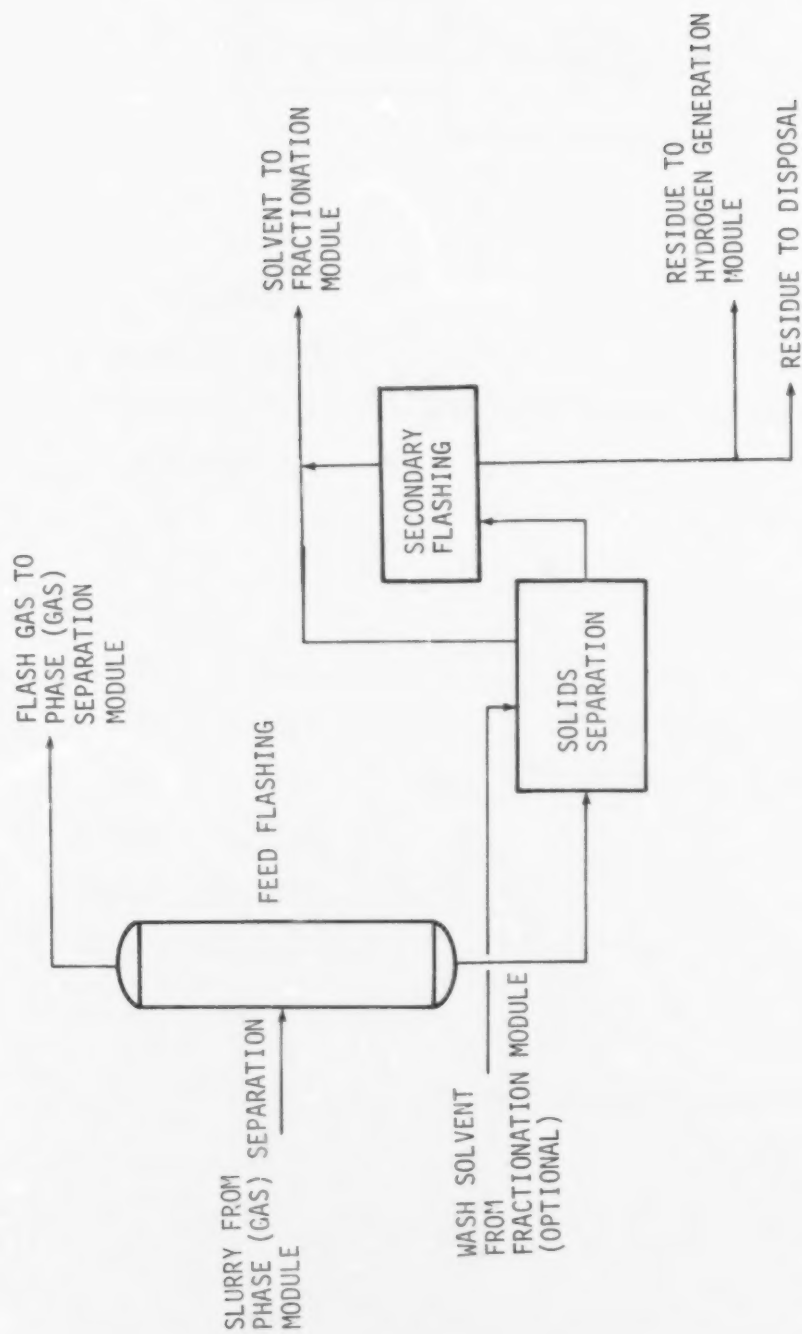
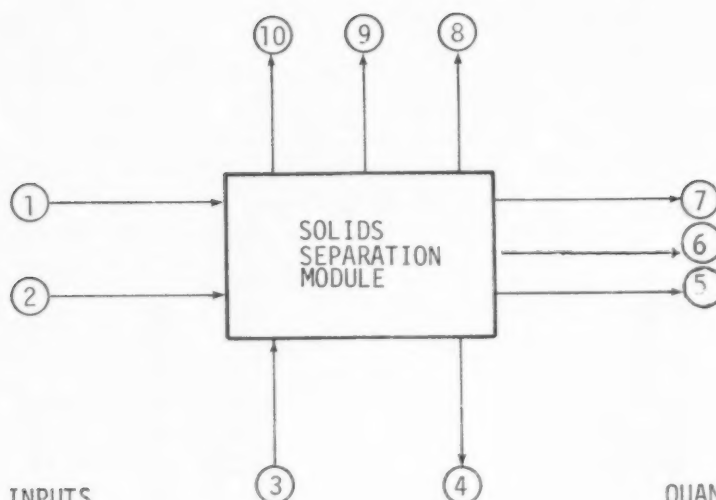


Figure 28. Process Flow Schematic Solids Separation Module



INPUTS	QUANTITY*	
	(TPD)	(Mg/day)
1. Slurry from Phase (gas) Separation Module	13241	12037
2. Wash solvent	NOT QUANTIFIED	
3. Fuel gas & air mixture	10777	9798
OUTPUTS		
4. Residue to Solidification	5575	5069
5. Solvent to fractionation module	6080	5527
6. Flash gas to phase (gas) separation module	1037	943
7. Flue gas	10777	9798
8. Vapor discharge	NOT QUANTIFIABLE	
9. Accidental Material Spills	NOT QUANTIFIABLE	

*Streams may not balance due to roundoff.

Figure 29. Solids Separation Module Process and Waste Streams

TABLE 46. PROCESS AND WASTE STREAM CONSTITUENTS
IN THE SOLIDS SEPARATION MODULE

		<u>QUANTITY*</u>	
STREAM		TPD	(Mg/day)
3	Fuel Gas and Air Mixture		
	Fuel Gas		
	N ₂	4.4	4.0
	CO	74.5	67.7
	CO ₂	0.7	0.6
	CH ₄	292.0	265.5
	C ₂ H ₆	183.3	166.6
	Air	10222.4	9293.1
7	Flash Gas to Phase (Gas) Separation		
	H ₂ S	11.1	10.1
	H ₂	45.8	41.6
	CO	63.7	57.9
	CO ₂	9.6	8.7
	HC	898.0	816.4
	H ₂ O	1.0	0.9
	NH ₃	7.5	6.8
8	Flue Gas		
	N ₂	8110.0	7372.7
	CO ₂	1503.4	1366.7
	H ₂ O	679.0	617.3
	O ₂	485.0	440.9

*Streams may not balance due to roundoff.

6.5.3 Control Equipment Specification and Cost Estimation

There is only one continuous waste stream discharged from the solids separation module, which is flue gas from mineral drying. There are no controls which must be applied to the flue gas prior to ultimate disposal since it contains only nitrogen, oxygen, water, and carbon dioxide.

6.6 Fractionation Module

6.6.1 Module Description

The main functions of the fractionation module are: (1) to separate the high boiling liquid SRC product from lower boiling fractions; (2) to combine light streams for fractionation into light products; and (3) to separate wash solvent for recycling to the solids separation module. Separations are accomplished in two unit operations, i.e., a vacuum flash and an atmospheric distillation.

In the operation, the main solvent stream from the solids separation module flows through a gas-fired preheater in which it is heated to a temperature of 800-875°F (427-467°C) (23). The hot stream is charged to a vacuum flash drum, in which the lighter fractions (gas) are separated from the high boiling SRC. The SRC stream is routed to product storage. The flash gas is condensed and charged to the light ends fractionation tower. Additional feed streams to light ends fractionation include the light and heavy oils from phase (gas) separation. Raw naphtha and fuel oil are taken off as fractionation products and routed to hydro-treating. An optional side-stream may be taken off and recycled to the solids separation module for use as a wash solvent. A schematic of the fractionation module may be seen in Figure 30.

6.6.2 Process and Waste Streams

Process and waste streams entering and leaving the fractionation module are shown in Figure 31. Fuel and flue gas constituents are quantified in Table 47.

There are two major waste streams emanating from the fractionation module, i.e. preheater flue gas, and either steam ejector condensate or vacuum pump emission, depending on which type of equipment is used for evacuating the flash vessel. The preheater flue gas will contain carbon dioxide, carbon monoxide, water, and trace amounts of unreacted hydrocarbons. Steam ejector condensate and vacuum pump emissions both contain significant quantities of organics. Steam ejector condensate flows to wastewater treatment. Vacuum pump emissions should be flared.

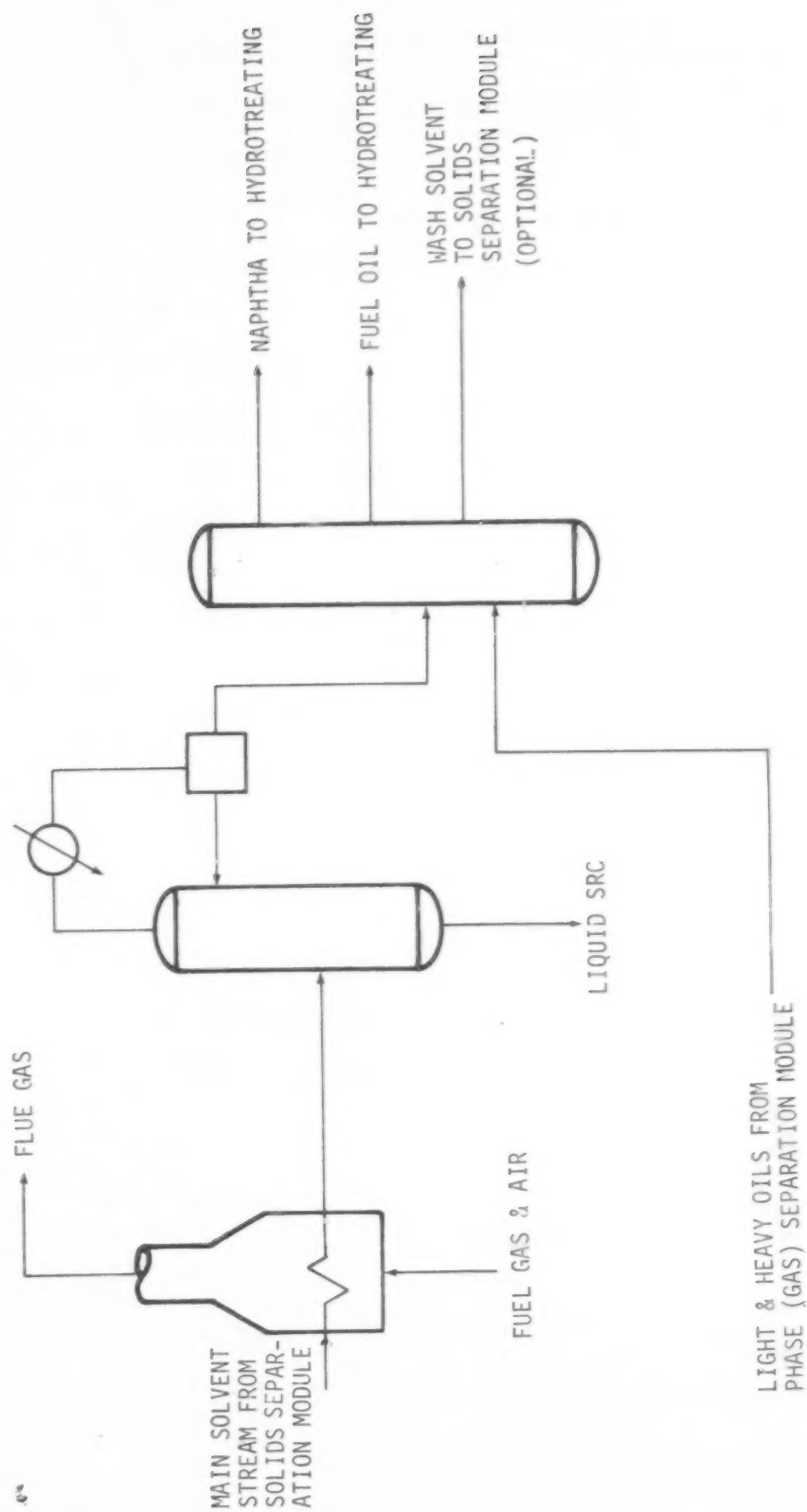
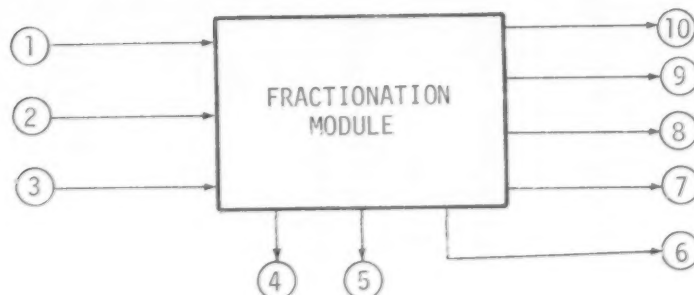


Figure 30. Process Flow Schematic Fractionation Module



<u>INPUTS</u>	<u>QUANTITY*</u>	
	<u>(TPD)</u>	<u>(Mg/day)</u>
1. Main stream from solids separation	6080	5527
2. Light & heavy oils from phase (gas) separation	3454	3140
3. Fuel gas and air mixture	2291	2083
<u>OUTPUTS</u>		
4. Accidental material spills	NOT QUANTIFIABLE	
5. Raw naphtha to hydrotreating	577	525
6. Raw fuel oil to hydrotreating	2877	2615
7. Product SRC	6080	5527
8. Wash solvent to solids separation module	NOT QUANTIFIED	
9. Vapor discharge	NOT QUANTIFIED	
10. Flue gas from preheater	2291	2083

*Streams may not balance due to roundoff.

Figure 31. Fractionation Module Process and Waste Streams

TABLE 47. FUEL GAS AND FLUE GAS CONSTITUENTS

STREAM	QUANTITY*	
	TPD	(Mg/day)
Preheater Fuel Gas		
CH ₄	62.1	56.4
C ₂ H ₆	39.0	35.4
CO	15.9	14.4
CO ₂	0.2	0.1
N ₂	0.9	0.8
Preheater Flue Gas		
CO ₂	319.7	290.6
H ₂ O	144.4	131.2
O ₂	103.1	93.7
N ₂	1724.3	1567.5

*Streams may not balance due to roundoff

6.6.3 Control Equipment Specification and Cost Estimation

The fractionation module generates one continuous waste stream, i.e. flue gas from the solvent preheater. The flue gas is generated from the combustion of product SNG; therefore, it is relatively contaminant free. It is vented, untreated, to the atmosphere at a rate of 2291 TPD (2083 Mg/day). As with previous modules, vapor discharges from pressure relief valves will be flared. Material leaks and accidental spills will be handled by proper maintenance procedures and spill contingency plans, as outlined in section 5.9.2.

6.7 Solvent Hydrotreating Module

6.7.1 Module Description

Hydrotreating involves the reaction of raw hydrocarbon streams with hydrogen to remove contaminants such as organic sulfur and nitrogen compounds, and to improve combustion characteristics so that they may meet commercial specifications. In the operation, organic sulfur and nitrogen compounds are converted to hydrogen sulfide and ammonia, which are stripped from the product stream. The hydrogenation reaction also serves to increase the hydrogen-to-carbon ratio, which improves the smoking characteristics of the fuel.

In the flow schematic shown in Figure 32, raw naphtha and fuel oil streams from the fractionation module are mixed with synthesis gas from the hydrogen production module (85% H₂ by volume) and pumped through a gas fired preheater into an initial catalyst guard reactor to permit the deposition of any remaining carbon on low surface-to-volume pelletized catalyst in order to prevent plugging of the main hydrotreating reactor. From the guard reactor, the fuel oil or naphtha stream is fed into a three section downflow hydrotreating reactor. Quench hydrogen injection points are spaced along the length of the reactors at appropriate locations for temperature control (40). Hydrotreating catalysts, such as cobalt molybdate are used. Space velocity is typically between 0.5 and 2 hour⁻¹ (41).

The gas-liquid product is cooled in a heat exchanger and fed to a high pressure flash drum where fuel oil or naphtha, water, and gas separation occurs. Approximately 60 percent of the gas is recycled into the hydrotreaters while the remainder is routed to the gas purification module (40).

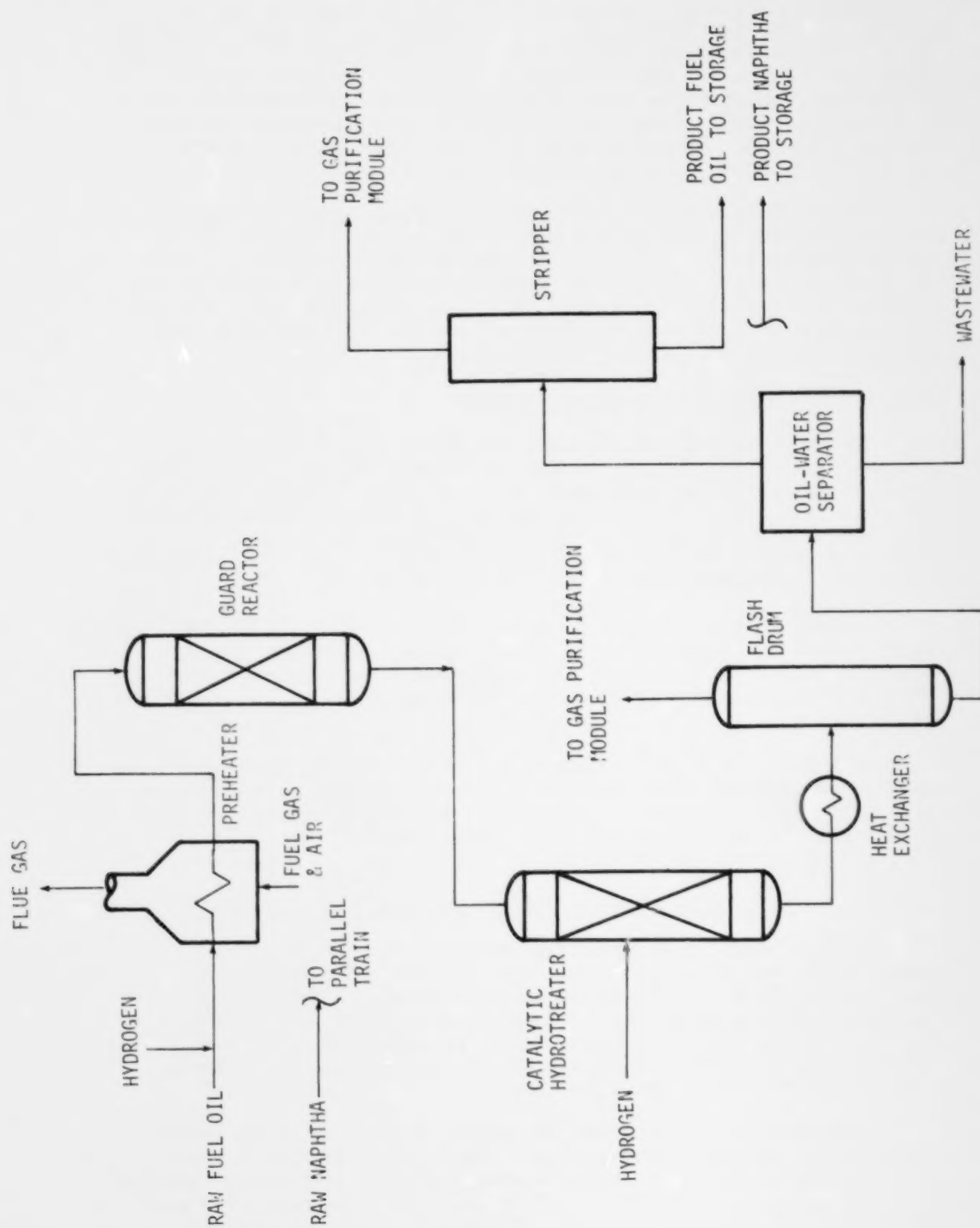


Figure 32. Process Flow Schematic Hydrotreating Module

About half the separated fuel oil or naphtha is recycled to the hydrotreaters. The remainder is depressurized into a receiving tank where the water fraction is separated from the solvent. The solvent fraction is pumped into a stripping tower where hydrogen sulfide and ammonia are taken off the top (40). The gas product of the stripper is sent to gas cleanup. Product fuel oil and naphtha streams are routed to product storage facilities.

Water formed by the hydrotreating reaction is separated from the hydrocarbon phase in the decanter. The water may contain substantial amounts of ammonia and organics. This wastewater is routed to the ammonia stripping column in the by-product recovery module. Any remaining hydrogen sulfide or ammonia in the main product stream is stripped and the off-gas is routed to gas purification.

6.7.2 Process And Waste Streams

Process and waste streams entering and leaving the hydrotreating module are shown in Figure 33. Constituents in specific process and waste streams are shown in Table 48. Several atmospheric, aqueous and solid wastes emanate from the hydrotreating module. Flue gas from the preheater is expected to contain carbon dioxide, water, and trace amounts of carbon monoxide and unreacted hydrocarbons.

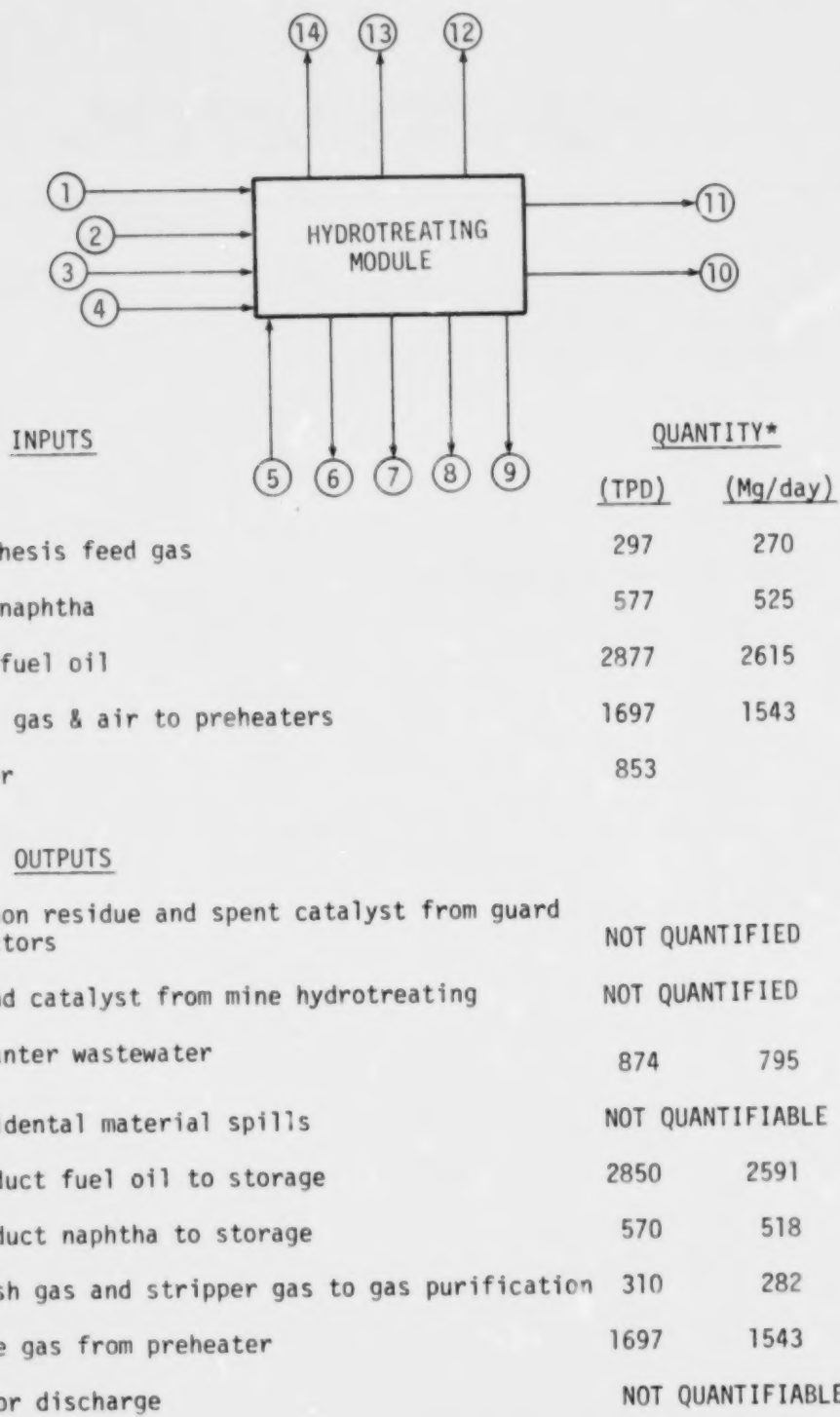
A solid waste stream consisting of carbon deposited on spent catalyst packing will be generated from the guard reactor. It may be possible to recover the carbon or regenerate the catalyst; however, the feasibility has not been explored.

A spent catalyst stream also is generated from the main catalytic hydrotreater as are non-condensable gases; these are routed to the gas purification module to remove water, hydrocarbons, hydrogen sulfide, and ammonia.

6.7.3 Control Equipment Specification and Cost Estimation

The solvent hydrotreating module has two continuous waste streams, flue gas from the solvent preheater and wastewater from an oil-water decant drum. Flue gas is vented to the atmosphere at the rate of 1697 TPD (1543 Mg/day). The decanter wastewater is combined with other wastewater streams and flows to the wastewater treatment facility, which is described later in this section.

Hydrocarbon vapors and material spills will be generated on an intermittent basis. There will be two intermittent solid waste streams emanating from the guard reactor and the main hydrotreater. They will be composed of spent catalyst and carbon residue. Disposal alternatives for these solid wastes can be found in Chapter 5.



*Streams may not balance due to roundoff.

Figure 33. Hydrotreating Module Process and Waste Streams

TABLE 48. PROCESS AND WASTE STREAM
CONSTITUENTS IN THE HYDROTREATING MODULE

	QUANTITY*	
	(TPD)	(Mg/day)
1. Synthesis feed gas from hydrogen production module		
H ₂	130.0	118.2
CO	130.0	118.2
CO ₂	29.5	26.8
N ₂	7.2	6.5
H ₂ S	0.1	0.1
4. Fuel gas and air mixture		
Fuel gas		
CH ₄	46.0	41.8
C ₂ H ₅	28.9	26.3
CO	11.7	10.6
CO ₂	0.1	0.1
N ₂	0.7	0.6
Air	1609.8	1463.4
8. Decanter wastewater		
H ₂ O	853.0	775.5
H ₂ S	10.0	9.1
NH ₃	11.0	10.0
12. Flash gas and stripper gas to gas purification		
H ₂	28.0	25.5
CO	36.6	33.3
H ₂ O	6.0	5.5
hydrocarbons	232.0	210.9
N ₂	7.2	6.5
H ₂ S	trace	
13. Flue gas from preheaters		
CO ₂	236.8	215.3
H ₂ O	106.9	97.2
N ₂	1277.1	1161.0
O ₂	76.4	69.4

*Streams may not balance due to roundoff.

6.8 Solidification Module

6.8.1 Module Description

The function of the solidification module is to cool the liquid residue stream into solid product suitable for gasification. There are a number of different solidification units available, the most promising being the metal belt, rotating drum, and rotating shelf types (42). The solidification process involves feeding the liquid stream onto a moving heat transfer surface. The surface may be in the form of a metal belt, drum, pan, or shelf. Cooling water is sprayed on the other side of the heat transfer surface to initiate cooling. Additional cooling may be provided by passing refrigerated air over the product stream (42). The cooled solid residue is scraped off the heat transfer surface with a knife and is transferred to gasification and/or disposal by screw conveyor.

Figure 34 shows schematics of two types of solidification units.

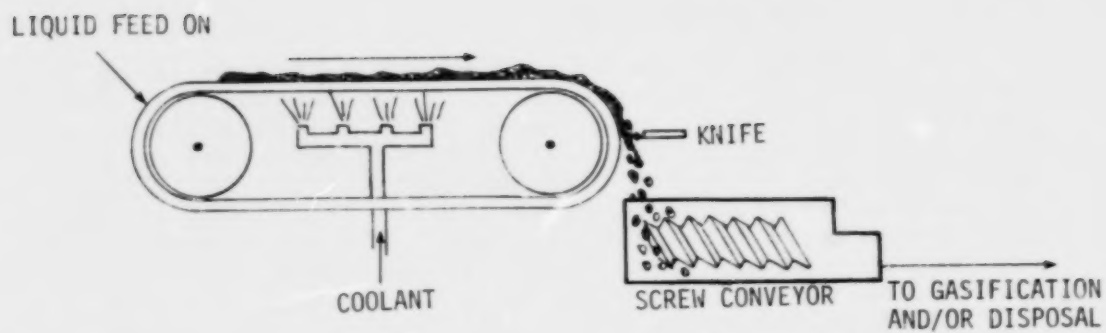
6.8.2 Process and Waste Streams

Process and waste streams entering and leaving the solidification module are shown in Figure 35. A large portion of the solid residue must be routed to disposal, which substantiates a significant environmental discharge. Alternates for recovery and disposal for the residue stream are given in the next section.

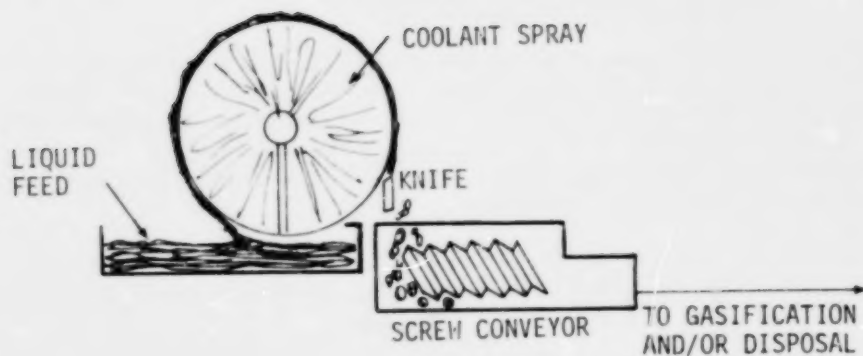
The only other waste stream in the solidification module consists of particulates and hydrocarbon gases vaporized from the SRC during cooling.

6.8.3 Control Specification and Cost Estimation

Approximately 4075 TPD (3705 Mg/day) of residue, containing significant quantities of polynuclear aromatics, unreacted coal, and mineral-matter, must be disposed of or utilized in the plant. Considering the large quantity of carbon which would be lost if the residue were landfilled directly, it is more feasible to gasify the remaining residue to produce low-grade fuel gas which can be utilized as fuel within the plant. In addition to producing a useful product, gasification of the residue would also significantly reduce the volume of solids which must ultimately be disposed of in a landfill. Assuming the residue to be

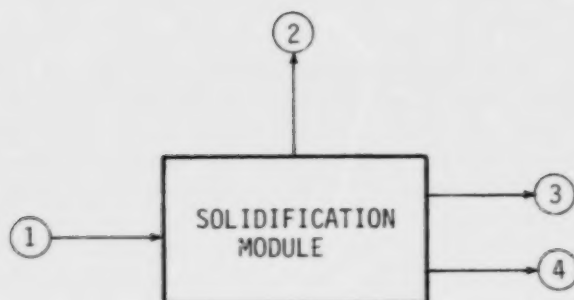


I. STEEL BELT SOLIDIFICATION
(SANDVIK SYSTEM)



II. ROTARY DRUM SOLIDIFICATION

Figure 34. Solidification Units



<u>INPUTS</u>	<u>TPD</u>	<u>Mg/DAY</u>
1. Liquid Residue From Solids Separation Module	5575	5069
<u>OUTPUTS</u>		
2. Vapors and Particulates From Cooling Unit	Not Quantified	
3. Solid Residue to Gasification	1500	1364
4. Solid Residue to Disposal	4075	3705

Figure 35. Process and Waste Streams in the Solidification Module

35 percent ash which will be converted to slag, and the solids content of the slag is 60 percent, then the volume of slag with moisture which would require transport to a landfill is approximately 2377 TPD (2161 Mg/day). Transportation costs for the disposal of the slag to a landfill are \$1 to \$8 per ton (\$0.9-7.0/Mg) for distances up to 150 miles (14). The costs, therefore, would range from \$2,377 to \$19,016 per day.

The only other continuous waste stream consists of the hydrocarbon fumes and dusts generated during residue solidification. No data are in the literature to quantify this stream. However, it is believed to carry a substantial waste load. Pollution control equipment sizing will depend partially on flow rate requirements for collection hoods. Operating data for the Sandvik cooling belt system, one way of solidifying the residue, are as follows (43):

Maximum belt length	=	160 ft (48.8m)
Operating belt speed	=	200 ft/min (61.0m/min)
SRC cake thickness	=	3/16 inch (0.5 cm)
Contact width of 59" belt	=	55" (139.7 cm)

Using the above operating conditions, it has been calculated that a total of eight cooling belt units are required, each unit requiring collection hood dimensions of 6 ft x 162 ft (1.8 m x 49.4 m). The following equation has been used to calculate design flow rates for low canopy hoods, as applied to hot processes (39).

$$\frac{V_t}{L} = 6.2 b^{4/3} D_t^{5/12}$$

where*

V_t = design flow rate, cfm

L = length of collection area, ft

b = width of collection area, ft

D_t = temperature difference between hot product and surrounding air, °F

*Metric conversion factors are given in the Appendix.

In the calculations, an average temperature difference of 300°F (149.0°C) is assumed, based on an ambient air temperature of 75°F (23.9°C) and an average product temperature of 375°F (190.5°C) (43). The calculations indicate a flow rate of 117,942 cfm/ unit (55.8 m³/sec) with a total

combined flow rate of 943,536 cfm ($443.5 \text{ m}^3/\text{sec}$). It was not possible to calculate grain loading since losses during solidification have not been quantified.

Treatment alternatives are similar to the dust control units selected in the coal preparation module, i.e., cyclone and baghouse, high efficiency cyclones, or wet scrubbers. Due to the lack of information on particulate loading, equipment costs and emissions after treatment could not be quantified.

6.9 Gas Purification Module

6.9.1 Module Description

The phase (gas) separation module and the hydrotreating module generate gases contaminated with hydrogen sulfide, ammonia, carbon dioxide, and small amounts of carbon disulfide and carbonyl sulfide. The substances are formed from the hydrogenation of phenols, aromatic amines, and mercaptans and sulfides naturally present in the parent coal. Reaction of the coal polymer and hydrogen yields these contaminant gases along with more saturated hydrocarbon molecules (desired product). Most of the contaminated gases also contain significant amounts of unreacted hydrogen and light hydrocarbon fractions. The gas purification module removes ammonia, hydrogen sulfide, carbon disulfide, carbon dioxide, and carbonyl sulfide from the gas stream, and leaves a purified gas which can be separated into hydrogen for recycle synthetic natural gas, liquid petroleum gas and light oils.

Figure 36 presents a schematic flow diagram of the gas purification module. The module consists of a number of parallel process trains, each train carrying out a similar function. A representative process train is depicted in this figure.

Generally, a gas stream entering the module would first be pumped to the acid gas removal section, consisting of an amine absorber. The gas stream is passed counter currently through a 15-20% solution of monoethanolamine (MEA) in the amine absorption tower (44). Hydrogen sulfide and carbon dioxide, present along with trace amounts of carbon disulfide and carbonyl sulfide, form complexes with the MEA, described by the following reactions:

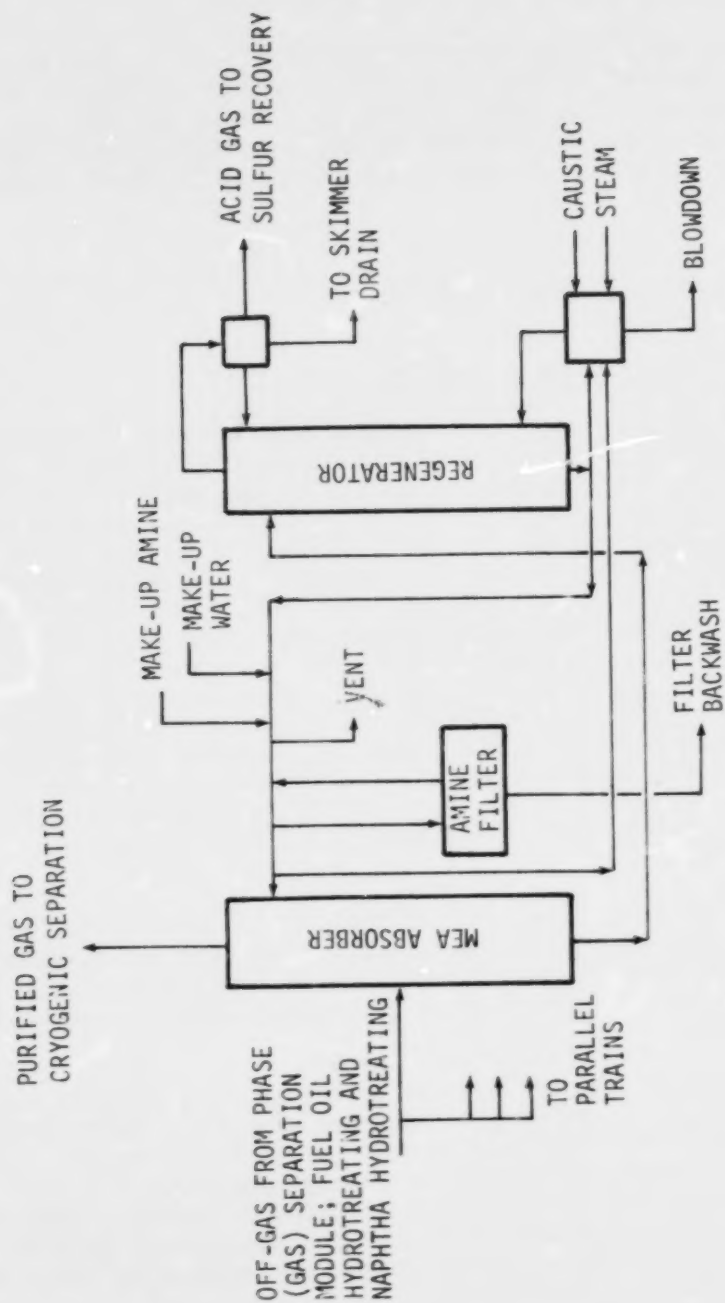
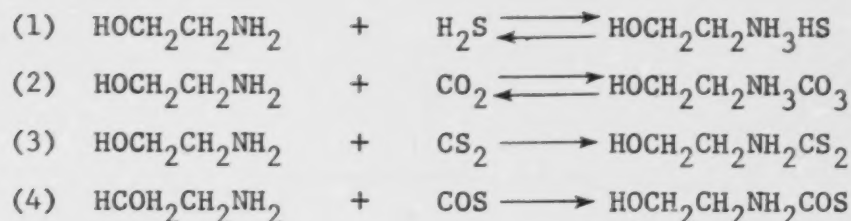


Figure 36. Gas Purification Module (One process train)



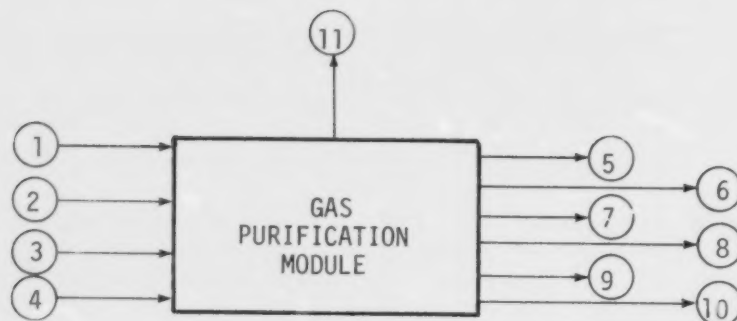
Only reactions (1) and (2) are reversible. The absorption process is essentially insensitive to the partial pressures of acid gases. Removal efficiencies have been estimated to be approximately 99.6 percent for H_2S and 88 percent for carbon dioxide (44).

The MEA absorbent is regenerated by thermal decomposition at elevated temperatures. Only hydrogen sulfide and carbon dioxide can be absorbed in this manner, with CS_2 and COS forming nonregenerable compounds with the amine. Off-gas from the amine regenerator, containing almost all of the hydrogen sulfide and carbon dioxide, is sent to sulfur recovery (23).

The nonregenerable organic complexes are removed by a purge stream from the reclaimer. Caustic added to the reclaimer to precipitate metals also forms non-volatile salts with the amine complexes, which are discharged as blowdown. Pure MEA is distilled off the reclaimer and recycled to the regeneration unit (23). The purified gas flows into the cryogenic separation unit where it is separated into hydrogen for recycle, synthetic natural gas, liquified petroleum gas, and light oils.

6.9.2. Process and Waste Streams

Process and waste streams entering and leaving the gas purification module are shown in Figure 37. Stream constituents are quantified in Table 49. The major wastewater streams are the blowdown from the amine regenerator and the ammonia scrubber effluent. An intermittent wastewater stream is backwashed from the amine filter in the acid gas removal unit. Frequency of backwash will depend on the flow rate and solids content of the amine stream. Accidental spills will also be a source of intermittent wastewater generation.



<u>INPUTS</u>		<u>QUANTITY*</u>	
		<u>(TPD)</u>	<u>(Mg/day)</u>
1.	Off-gas from phase (Gas) separation and hydrotreating	5583.0	5080.0
2.	Make-up water to amine system	3.0	3.0
3.	Additives to amine system	0.9	0.8
4.	Steam to amine regenerator	NOT QUANTIFIED	
<u>OUTPUTS</u>			
5.	Acid gas to sulfur recovery	775.0	705.0
6.	Purified gas to cryogenic separation module	4812.0	4374.0
7.	Wastewater from acid gas removal	6.0	6.0
8.	Filter backwash wastewater	NOT QUANTIFIED	
9.	Accidental material spills	NOT QUANTIFIABLE	
10.	Fugitive atmospheric emissions	NOT QUANTIFIABLE	
11.	Vents from storage and sump facilities	NOT QUANTIFIED	

*Streams may not balance due to roundoff.

Figure 37. Process and Waste Streams in the Gas Purification Module

TABLE 49. PROCESS AND WASTE STREAM CONSTITUENTS
IN THE GAS PURIFICATION MODULE

		QUANTITY*	
		TPD	(Mg/day)
1.	Off-gas from Phase (gas) Separation		
	H ₂	563.7	511.9
	H ₂ S	424.1	385.5
	N ₂	18.5	16.8
	H ₂ O	40.0	36.4
	HC	3545.9	3223.5
	NH ₃	0.2	0.2
	CO	397.8	361.6
	CO ₂	288.8	
	Flash gas from Hydrotreating		
	H ₂	28.0	25.5
	CO	36.6	33.3
	H ₂ O	6.0	5.5
	HC	232	210.9
	N ₂	7.2	6.5
	H ₂ S	trace	
4.	Additives to Amine System		
	Monoethanol Amine (MEA)	0.6	0.5
	Polyrad 1110A (Corrosion inhibitor)	0.003	0.003
	Oleyl Alcohol (Anti-foam)	0.007	0.007
	Sodium hydroxide	0.3	0.3
6.	Acid gas to sulfur recovery		
	H ₂ S	422.4	384.0
	H ₂ O	11.0	10.0
	HC	56.0	50.9
	CO	1.4	1.3
	CO ₂	284.4	258.5

*Streams may not balance due to roundoff.

TABLE 49. PROCESS AND WASTE STREAM CONSTITUENTS
IN THE GAS PURIFICATION MODULE (Continued)

	QUANTITY*	
	TPD	(Mg/day)
7. Purified gas to cryogenic separation module		
H ₂	591.7	537.9
N ₂	25.7	23.4
H ₂ O	35	
HC	3721.9	3383.5
NH ₃	0.2	0.2
CO	433.0	393.6
CO ₂	4.1	3.7
8. Wastewater from acid gas removal		
H ₂ O	3.2	2.9
H ₂ S	1.7	1.5
CO ₂	0.3	0.3
MEA	0.6	0.5
Polyrad 1110A	0.003	0.003
Oleyl Alcohol	0.007	0.007
NaOH	0.3	0.3

*Streams may not balance due to roundoff.

Wastewater from the gas purification will contain substantial amounts of dissolved and suspended hydrocarbons; monoethanolamine; suspended solids; sodium salts of monoethanolamine and carbon disulfide or carbonyl sulfide compounds, metals, ammonia, and other minor constituents. Large quantities of caustic, ammonia, and amine will result in an alkaline wastewater.

Atmospheric emissions will consist of gas leakage from sumps and storage vents, and fugitive emissions during maintenance operations. No attempt has been made to quantify specific constituents. All volatile constituents appearing in Table 12 are potential atmospheric contaminants.

6.9.3 Control Equipment Specification and Cost Estimation

Two wastewater streams are generated in the gas purification module: blowdown from the amine scrubber (6.0 TPD, or 5.5 Mg/day), and filter backwash wastewater (not quantified). The first stream is routed to the wastewater treatment plant.

Gaseous emissions include fugitive vapors and vent gases from storage and sump facilities. These waste streams should be directed to the flare system for combustion (See Flare Systems, Section 6.14).

6.10 Cryogenic Separation Module

6.10.1 Module Description

Purified gases entering the cryogenic separation module are separated into recycle hydrogen (99% pure), synthetic natural gas, liquified petroleum gas, and light oils. A flow diagram of a theoretical cryogenic separation module is shown in Figure 38.

Generally, purified gas from the gas purification module flows to a series of cryogenic separators. The gas stream is first compressed and condensed in a multistage refrigeration unit, then charged to a flash tower. The liquid stream consists of light oils, water, and dissolved ammonia. The liquid stream is charged to a fractionation tower where various hydrocarbon streams are taken off as product. The water and ammonia are removed as a separate side stream and routed to wastewater treatment. The flash gas contains lighter hydrocarbons, hydrogen, nitrogen, carbon dioxide, and carbon monoxide. The flash gas is compressed and condensed in another multistage refrigeration unit and is charged to a de-ethanizer column. Liquefied petroleum gas (propane and butane) is taken off the bottom, while the overhead gases are charged to another refrigeration unit and distillation column (41,44).

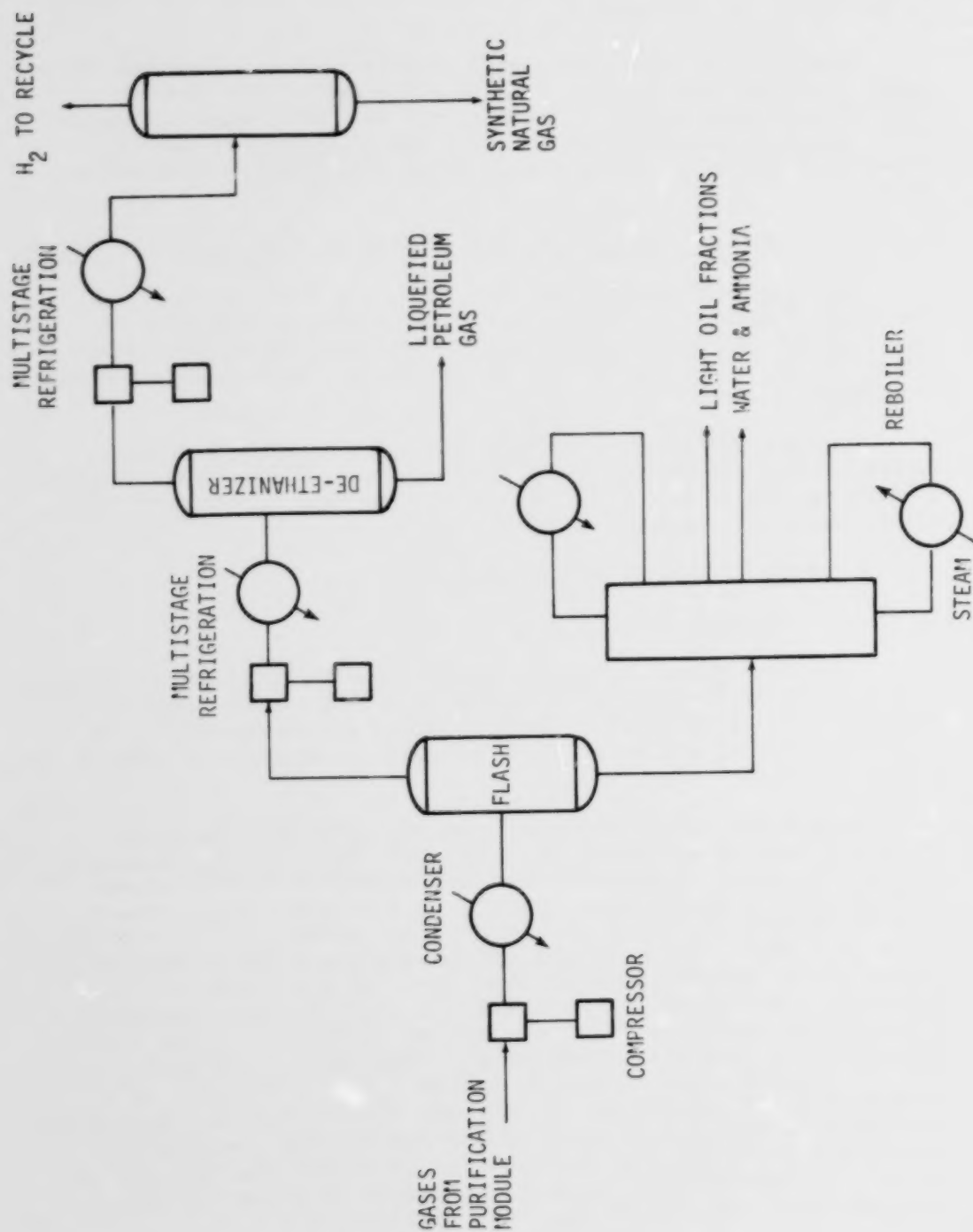


Figure 38. Cryogenic Separation Module Process Flow Schematic

Pure hydrogen is taken off the top and combined with hydrogen from gasification for recycle to the hydrogenation module. Synthetic natural gas consisting mostly of methane, ethane, and carbon monoxide is taken off as the condensed stream and used for fuel gas or is sold as product.

The process scheme above is one of several alternatives for the cryogenic separation module, depending on the desired end products.

6.10.2 Process and Waste Streams

Process and waste streams entering and leaving the cryogenic separation module are shown in Figure 39. Compositions of input and output streams are given in Table 50. The only known wastewater stream is the water and ammonia sidestream from light oil distillation, containing a substantial amount of phenols and dissolved hydrocarbons. A conservative estimate of these concentrations are 1 percent phenols and 0.2 percent hydrocarbons.

6.10.3 Control Equipment Specification and Cost Estimation

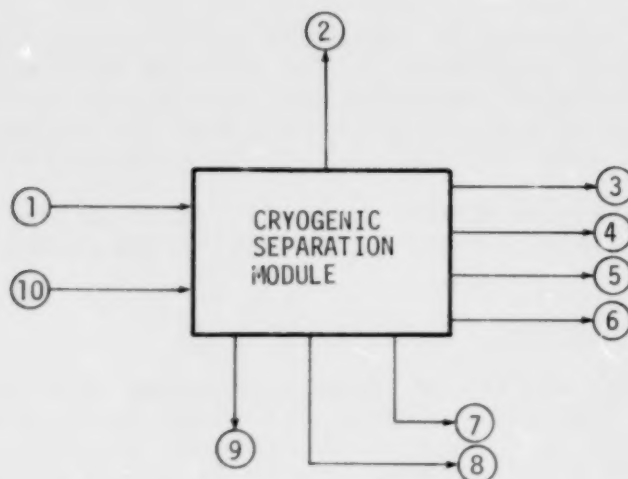
The only wastewater stream generated in cryogenic separation consists of an ammonia-water sidestream from the light oil distillation (36 TPD or 33 Mg/day). It flows to the ammonia stripping unit in by-product recovery, so no control equipment specification is necessary here.

6.11 Hydrogen Production Module

6.11.1 Module Description

Hydrogen is an essential component of the SRC process. In order to produce liquid fuels from coal, it is necessary for the hydrogen/carbon ratio by weight in coal to be on the order of 1:(6-10) (45). Since the hydrogen/carbon ratio in unprocessed coal is only about 1:(15-20), hydrogen must be supplied on site either by generation from the gasification of coal, carbon residues, and/or char or by the recovery of hydrogen from gases generated during the liquefaction process (45). This module involves the production of hydrogen from coal and coal products. Figure 40 shows the hydrogen production module unit (46).

Four main operations steps employed in the production of hydrogen from coal are gasification, quenching, shift conversion, and hydrogen compression. Numerous pollution control devices are also used to purify the hydrogen gas stream prior to its distribution to hydrogenation and hydrotreating operations.



<u>INPUTS</u>	<u>QUANTITY*</u>	
	<u>(TPD)</u>	<u>(Mg/day)</u>
1. Purified gas from Gas purification module	4812	4374
10. Steam	NOT QUANTIFIED	
<u>OUTPUTS</u>		
2. Fugitive discharge	NOT QUANTIFIABLE	
3. Hydrogen to recycle	592	538
4. Synthetic natural gas	3225	2932
5. Liquefied petroleum gas	903	821
6. Light oils	57	52
7. Wastewater	36	33
8. Accidental material spills	NOT QUANTIFIABLE	
9. Steam condensate	NOT QUANTIFIED	

*Streams may not balance due to roundoff.

Figure 39. Cryogenic Separation Module Process and Waste Streams

TABLE 50. PROCESS AND WASTE STREAM CONSTITUENTS IN
THE CRYOGENIC SEPARATION MODULE

		QUANTITY*	
		(TPD)	(Mg/day)
1.	Purified gas from gas purification		
	H ₂	591.7	537.9
	N ₂	25.7	23.4
	H ₂ O	35.0	31.8
	HC	3721.9	3383.5
	NH ₃	0.2	0.2
	CO	433.0	393.6
	CO ₂	4.1	3.7
3.	Hydrogen to recycle	591.7	537.9
4.	Synthetic natural gas		
	CH ₄	1697.0	1542.7
	C ₂ H ₆	1065.0	968.2
	N ₂	25.7	23.4
	CO	433.0	393.6
	CO ₂	4.1	3.7
5.	Liquefied petroleum gas		
	C ₃ H ₈	637.8	579.8
	C ₄ H ₁₀	265.0	240.9
6.	Light oils	56.7	51.5
7.	Wastewater		
	H ₂ O	35.0	31.8
	NH ₃	0.2	0.2
	Hydrocarbons	0.07	0.07
	Phenols	0.4	0.4

*Streams may not balance due to roundoff

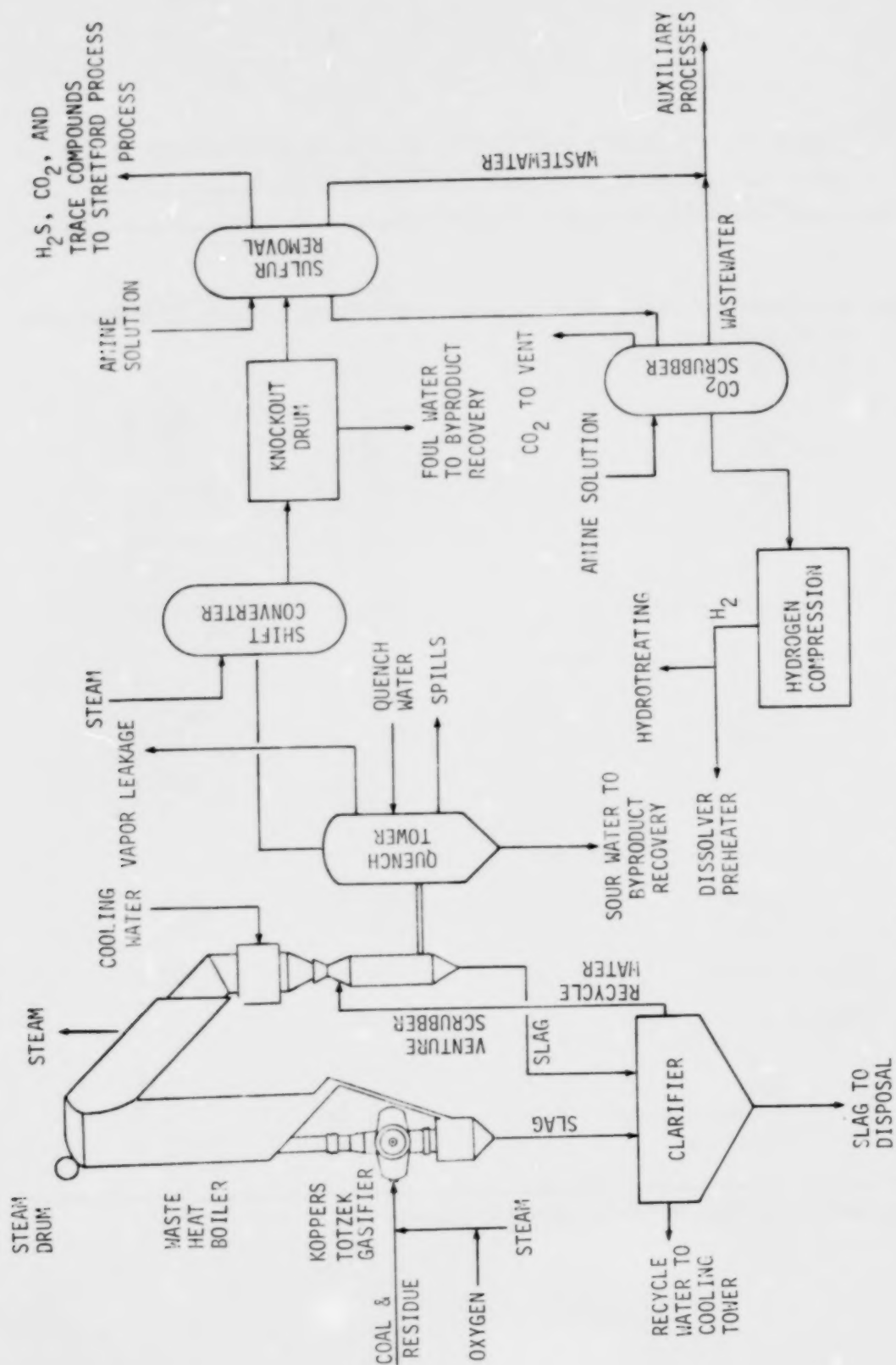


Figure 40. Hydrogen Generation

Mineral residue from the solids/liquid separation area, which contains heavy products, ash, and undissolved coal, is mixed with coal and subsequently introduced into a Koppers Totzek gasification unit. Oxygen and steam are injected into the coal/residue mixture prior to entering the gasifier. The gasifier operating conditions are 3330-3500°F (1815-1927°C) and 14.7 psig (0.1 MPa) (46).

A mixture of hydrogen, carbon monoxide, carbon dioxide, hydrogen sulfide, water, and other trace gases are produced in this process. Approximately 50 percent of the slag also produced in this process is carried along with the product gas (46). The remainder drops to the bottom of the gasifier where it is water quenched. The slag slurry is then sent to a clarifier where it is concentrated.

Prior to entering a venturi scrubber, the high temperature gasifier product gas produces steam in a waste heat boiler. Cooling water recirculated from the slag clarifier is introduced into the scrubber to remove 99+ percent of the remaining slag from the product gas (46). This slag slurry is then mixed with the slag from the gasifier and concentrated in a clarifier prior to removal to a landfill.

The gas is then water quenched to remove impurities such as tar acids, ammonia, hydrogen sulfide, carbon dioxide, and slag. The sour water stream is sent to by-product recovery.

The quench tower effluent process stream is further processed in a CO shift operation where carbon monoxide reacts with steam to produce hydrogen and carbon dioxide. This operation supplements the hydrogen already present in the product gas stream. Temperatures and pressures in the shift reactor are expected to range from 645-700°F (340-371°C) and 140-1400 psig (9.7 MPa) (36). A catalyst is needed in this process. Foul water from the shift reaction is directed to by-product recovery.

An amine scrubbing unit removes both hydrogen sulfide and carbon dioxide from the clean product gas stream. A subsequent CO₂ scrubbing unit removes most of the remaining CO₂. The gases removed from the first unit are sent to a Stretford sulfur recovery unit while the CO₂ removed from the second scrubbing unit is vented to the atmosphere.

The clean product gas is then compressed and distributed to hydrotreating and hydrogenation operations.

6.11.12 Process and Waste Streams

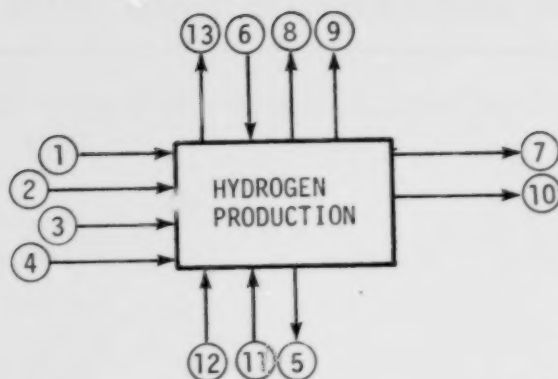
Figure 41 shows the hydrogen production module influent and effluent process and waste streams. Stream compositions are enumerated in Table 51.

It has been estimated that approximately 2.5 percent hydrogen by weight per ton of coal is needed to produce liquid products (23). Usually, 5.0 percent hydrogen is supplied to ensure completion of hydrogenation reactions. For 20,000 tons of processed coal per day (18182 Mg/day), about 1,000 tons (909 Mg) of hydrogen are needed (23).

The amount of hydrogen which must be generated on-site to meet the specified hydrogen requirements depends on the volume of hydrogen recycled to the hydrogenation reactor from gas purification and the amount of hydrogen required for hydrotreating operations. The material balance shown in Figure 41 was based on returning 321 TPD (292 Mg/day) hydrogen to the hydrogenation reactor and 130 TPD (118 Mg/day) to hydrotreating. The remaining hydrogen needed in the hydrogenation reactor is provided by the recycled synthesis gas from gas purification.

Several water and gaseous waste streams are discharged during the production of hydrogen including the following:

- Sour water and foul water waste streams are discharged continuously from the hydrogen production module. These streams may contain ammonia, tar, and oils with the foul water containing higher quantities of these constituents. Both of these streams are directed to the wastewater treatment facilities at a rate of approximately 883 TPD (803 Mg/day).
- Sulfur compounds and carbon dioxide are discharged from an amine scrubbing unit to the Stretford process at a rate of approximately 6366 TPD (5787 Mg/day) (36). Other impurities such as SO₂, HCN, COS, NO, NH₃, argon, and ash are also discharged along with the hydrogen sulfide and carbon dioxide. They amount to approximately 43 TPD (39 Mg/day). Purge wastewater streams from these operations are directed to the wastewater treatment facilities.
- Carbon dioxide is vented to the atmosphere from the CO₂ scrubber at a rate of 752 TPD (684 Mg/day).



STREAM	QUANTITY*	
	(TPD)	(Mg/day)
1. Residue and Coal	3021	2753
2. Oxygen	2806	2551
3. Steam	4470	4064
4. Water	738	671
5. Slag and Water (60% slag)	1692	1538
6. MEA Solution	1	0.9
7. Wastewaters	883	803
8. Acid Gas	6409	5826
9. CO ₂ from Scrubber	752	684
10. Product Gas	1031	937
11. Fuel Gas	58	52
12. Air	1069	965
13. Flue Gas	1119	1017
14. Recycle Water to Cooling Towers	269	245

*Streams may not balance due to roundoff.

Figure 41. Hydrogen Production Module

TABLE 51. HYDROGEN PRODUCTION MODULE STREAM COMPOSITION

STREAM	QUANTITY*	
	(TPD)	(Mg/day)
3. Steam		
To gasifier	1,208.0	1,098.2
To shift converter	3,262.0	2,965.4
4. Water		
Gasifier	510.0	463.6
Quench tower	225.0	204.5
Acid gas removal (MEA solution)	1.8	1.6
Carbon dioxide removal (MEA solution)	1.2	1.1
6. MEA Solution		
<u>To Acid-Gas Recovery</u>		
MEA	0.4	0.4
NaOH	0.3	0.3
Polyrad	0.002	0.002
Alcohol	0.005	0.005
COS	0.92	
<u>To CO₂ Removal</u>		
MEA	0.3	0.3
Polyrad	0.001	0.001
Alcohol	0.003	0.003
7. Wastewaters		
Quench operation	225.2	204.7
Shift	653.5	594.1
Acid gas (MEA solution)	3.4	3.1
CO ₂ removal (purge) (MEA Solution)	1.4	1.3
8. Acid Gas		
H ₂ S	96.2	87.4
CO ₂	6,270.0	5,700.0
SO ₂	0.2	0.1
HCN	1.5	1.4
NO	0.006	0.006
NH ₃	0.7	0.6
Ash	4.4	4.0
Argon	36.1	32.8

*Streams may not be balanced due to roundoff.

TABLE 51. HYDROGEN PRODUCTION MODULE
STREAM COMPOSITIONS (Continued)

STREAM	QUANTITY*	
	(TPD)	(Mg/day)
10 Product gas		
H ₂	451.0	410.0
CO	451.0	410.0
N ₂	25.7	23.4
CO ₂	102.6	93.3
H ₂ S	0.4	0.4
11 Fuel gas		
N ₂	0.5	0.4
CO	7.7	7.0
CO ₂	0.07	0.07
CH ₄	30.3	27.5
C ₂ H ₆	19.0	17.3
13 Flue gas		
CO ₂	156.1	141.9
N ₂	842.0	765.4
O ₂	50.4	45.8
H ₂ O	70.5	64.1
14 Water to cooling tower	269.0	244.5

*Streams may not be balanced due to roundoff

- Flue gas is discharged at a rate of 1128 tons per day (1025.4 Mg/day) as a result of the operation of the gasifier.
- Spent catalyst is occasionally discharged from the shift converter to a regeneration operation.
- Slag, removed from the gasifier and venturi scrubbers, is concentrated in a clarifier for disposal at a rate of 1692 TPD (1538 Mg/day). Water is recirculated from the clarifier to the venturi scrubbers at a rate of 6000 TPD (5454.5 Mg/day). Excess water is returned to the cooling tower circuit from the clarifier at a rate of 269 TPD (245 Mg/day).
- Other discharges from the hydrogen production area include hydrocarbon vapor leakage and spills in the vicinity of the quench tower.
- Spent MEA solutions from the amine and CO₂ scrubbing units are to be discharged along with the slag at a rate of 4.0 TPD (3.6 Mg/day) (36).

6.11.3 Control Equipment Specification and Cost Estimation

There are several waste streams discharged to the environment from the hydrogen production module. Table 52 lists the various waste streams, volumes, and applicable control measures.

TABLE 52. HYDROGEN PRODUCTION WASTE STREAMS

Waste	Quantity of Waste		Control Measure
	(TPD)	(Mg/day)	
Carbon dioxide from scrubber	752.0	684.5	Vent to atmosphere
Flue gas from gasifier	1,128.0	1,025.4	Vent to atmosphere
Spent MEA solution from amine and CO ₂ scrubbing units	4.0	3.6	Add to gasifier slag and dispose of in landfill
Slag from venturi scrubbers and gasifier	1,692.0	1,538.2	Dispose of in landfill
Spent catalyst from shift conversion	not quantifiable		Dispose of in landfill
Spills	not quantifiable		Dike spill-prone areas, collect spills in sump, and return spills to process or wastewater treatment plant

The costs associated with landfilling sludges produced during hydrogen generation are given in Table 53.

TABLE 53. SLUDGE LANDFILLING (14)

Process	Cost	Annual Total Cost
	\$/ton	\$
Sludge transport	\$3.00	49,338.75
Landfill costs	\$8.50	139,793.13
	Total	189,131.88

It is anticipated that the spent MEA solutions will be mixed with the slag sludges prior to landfilling.

In addition to the wastes listed in Table 52, there are also two wastewater streams amounting to 883 TPD (803 Mg/day) which are discharged to the wastewater treatment facilities, and a gaseous waste stream amounting to 7366 TPD (6696 Mg/day) which is directed to the Stretford process. No control measures are applied to these streams in route.

Carbon dioxide from the CO₂ scrubber and flue gas from the gasifier, totaling 1821 TPD (1655 Mg/day), are vented to the atmosphere without any controls as they are non-toxic. Spills and vapor leakage are controlled by dikes and proper maintenances, respectively. Since these wastes are non-quantifiable, costs of controls could not be generated.

6.12 Auxiliary Processes Modules

6.12.1 Introduction

In addition to the main process modules previously discussed, there are numerous auxiliary processes which must be incorporated into the overall SRC-II system in order to transform coal into suitable end products. These processes are used for the recovery of by-products, such as sulfur, ammonia, and phenol from waste streams, to furnish necessary utilities such as water, steam, and power, and to furnish feed materials such as oxygen.

6.12.2 Ammonia Recovery

6.12.2.1 Process Description

Ammonia may be recovered from numerous coal liquefaction operations such as hydrogen production, hydrotreating, and cryogenic separation. Wastewater streams containing ammonia from each of these operations are directed to a two-stage ammonia recovery stripping tower system (4). A typical ammonia recovery process is shown in Figure 42 (4).

In order to remove ammonia from the combined wastewater stream, the pH must first be raised to approximately 11.0 by the addition of calcium oxide. The wastewater then passes through a clarifier, to remove any excess lime as sludge, prior to entering the first stripping tower. This sludge is recycled through a lime recovery unit to the lime slaker hopper.

In the first stripping tower, the ammonia wastewater stream flows downward through a packing media where it contacts counter-currently with air. This air stream removes a significant portion of the ammonia from the wastewater.

A second tower is used further to increase the quantity of ammonia recovered from the wastewater. Upwards of 90 percent ammonia removal may be expected with this system (4).

6.12.2.2 Process and Waste Streams

Process and waste streams are shown in Figure 43. Stream compositions are given in Table 54. Effluent wastewater from the stripping towers is the only waste stream discharged from the ammonia recovery process. The gaseous ammonia product discharged from the towers is directed to by-product storage.

6.12.2.3 Control Equipment Specification and Cost Estimation

Effluent wastewaters from the ammonia recovery process are directed to the wastewater treatment facilities; consequently, there are no pollution control measures which must be implemented here.

AMMONIA RECOVERY

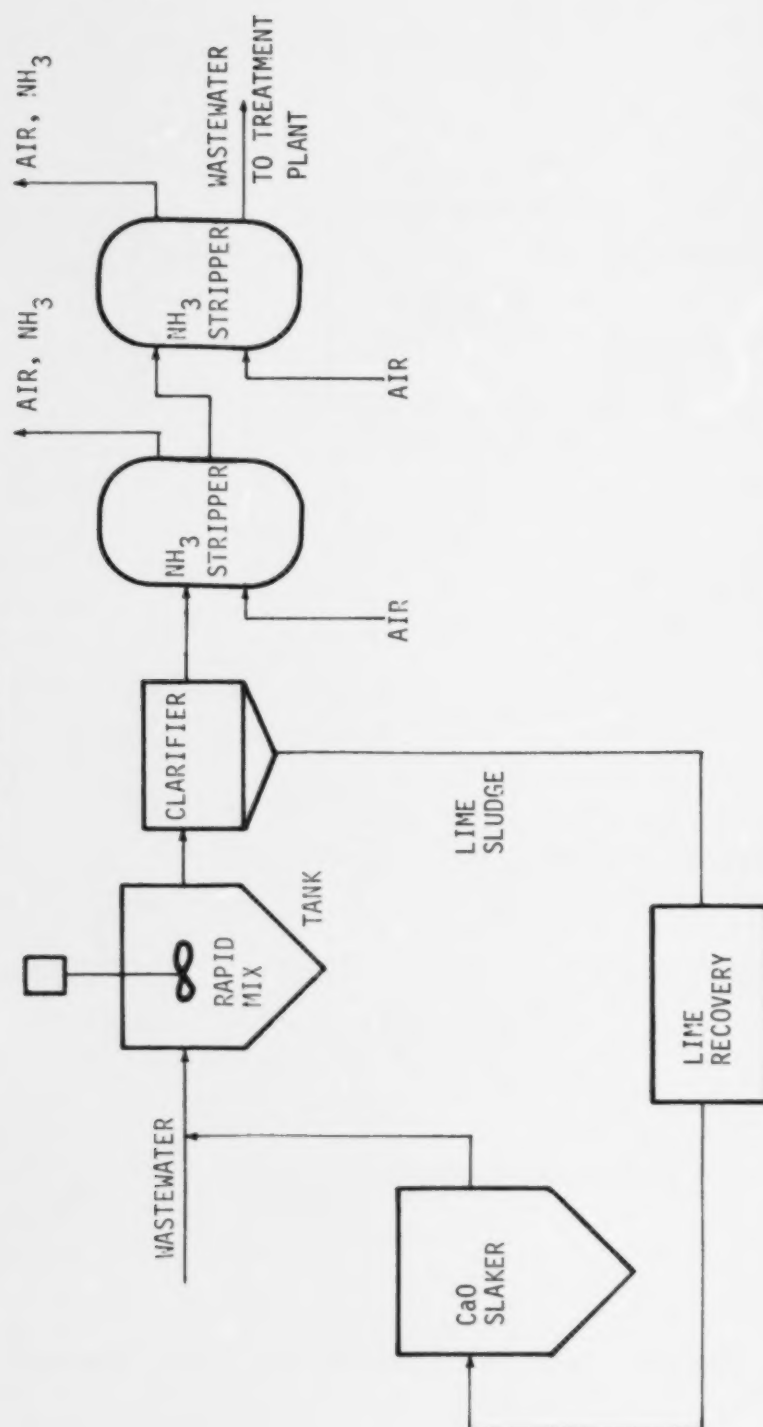
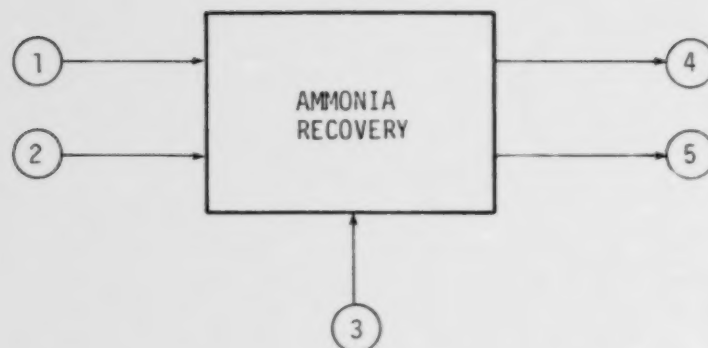


Figure 42. Ammonia Recovery



		<u>QUANTITY*</u>	
		<u>(TPD)</u>	<u>(Mq/day)</u>
1.	Wastewater	4279	3890
2.	Calcium hydroxide solution	8	7
3.	Air	16264	14786
4.	Ammonia stream	16335	14850
5.	Wastewater	4217	3833

*Streams may not balance due to roundoff.

Figure 43. Ammonia Recovery Process and Waste Streams

TABLE 54. AMMONIA STRIPPING STREAM COMPOSITIONS

Stream	Quantity*	
	(TPD)	(Mg/day)
1. Wastewater		
Water	4,194.6	3,813.3
H ₂ S	54.9	49.9
NH ₃	71.0	64.5
HC	2.4	2.2
Phenol	0.8	0.7
4. Ammonia Stream		
Air	16,264.5	14,785.9
NH ₃	70.3	63.9
5. Wastewater		
Water	4,201.5	3,819.5
NH ₃	0.7	0.6
H ₂ S	54.9	49.9
HC	2.4	2.2
Phenol	0.8	0.7
Ca(OH) ₂	1.4	1.3

*Streams may not balance due to roundoff

6.12.3 Phenol Recovery

6.12.3.1 Process Description

One of the most common methods used for recovering phenol is solvent extraction. It is proposed to use product naphtha to recover phenol in the by-product recovery area. Approximately 99 percent of the phenol is expected to be removed (7). A typical phenol recovery auxiliary process is shown in Figure 44 (7).

The pH of the phenolic water from phase (gas) separation is first adjusted to about 4.0 by the addition of hydrochloric acid. The acidic wastewater is then directed through a series of vessels where it contacts naphtha solvent. The naphtha solvent and wastewater streams pass counter-currently through the vessels so that the most concentrated solvent stream is contacted by the most concentrated phenolic wastewater stream. The amount of phenol which can be removed is dependent upon the number of vessels and the ratio of phenol to solvent flow. Economic considerations determine the number of vessels and solvent flow rate to be used. Since economic analyses are not considered here, it was assumed that the solvent flow rate would be equal to the phenolic wastewater flow rate and that an unspecified number of vessels would be required to remove 99 percent of the phenol. The effluent from the extraction process is directed to the wastewater treatment facilities.

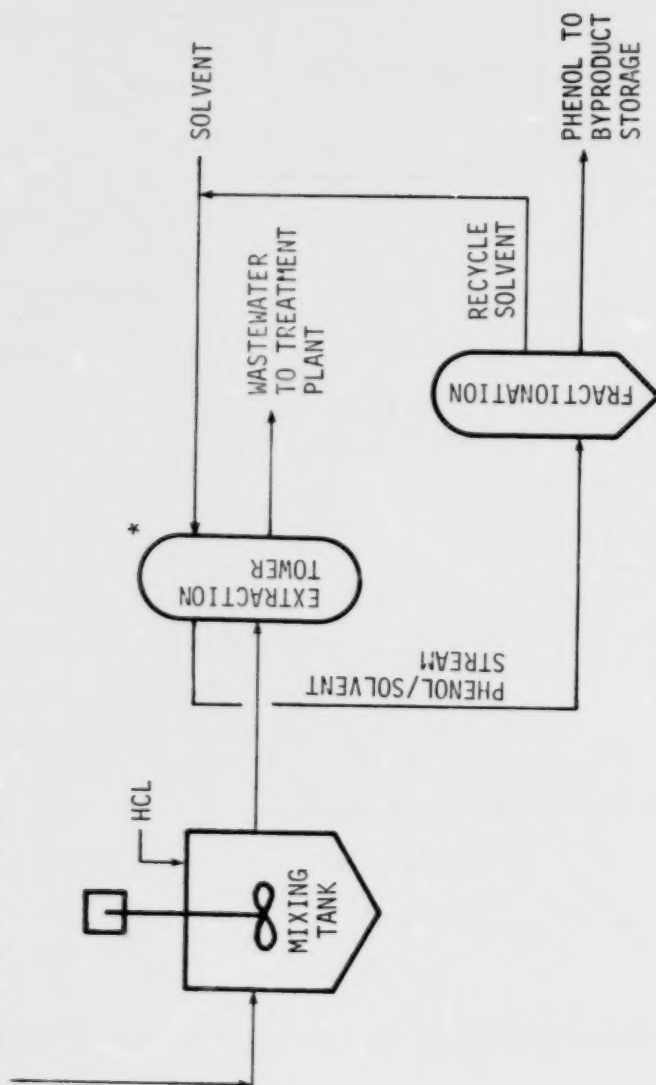
In addition to extracting phenols, the solvent also extracts other hydrocarbons from the wastewater. In the process of extracting hydrocarbons, however, a small portion of the naphtha is partitioned into the wastewater, since it is slightly soluble in water.

The phenol/solvent stream is sent to a fractionation tower where the phenol is separated from the solvent. The solvent is recycled back to the extraction process, and the phenol is directed to by-product storage.

6.12.3.2 Process and Waste Streams

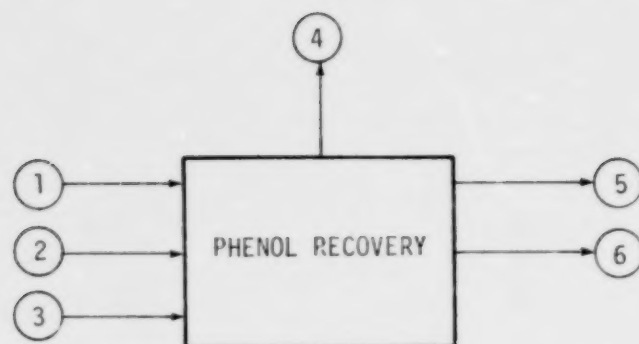
Process and waste streams are shown in Figure 45. Stream compositions are given in Table 55. Effluent wastewater from the extraction towers is the only waste stream discharged from the phenol recovery process. Recovered phenol is directed to by-product storage.

WASTEWATER FROM PHASE (GAS) SEPARATION



*There are a number of towers in series

Figure 44. Phenol Recovery



<u>STREAM</u>	<u>QUANTITY*</u>	
	<u>(TPD)</u>	<u>(Mg/day)</u>
1. Wastewater from phase (gas) separation	3449	3136
2. Solvent - Naphtha	2447	2225
3. HCl solution	34	31
4. Phenols	37	34
5. Wastewater	3414	3104
6. Naphtha	2445	2222

*Streams may not balance due to roundoff.

Figure 45. Phenol Recovery Process and Waste Streams

TABLE 55. PHENOL RECOVERY STREAM COMPOSITIONS

Stream	Quantity*	
	(TPD)	(Mg/day)
1. Wastewater from phase (gas) separation		
Phenol	37.8	34.4
Water	3,306.6	3,006.0
NH ₃	59.8	54.4
H ₂ S	44.9	40.8
5. Wastewater		
Water	3,306.6	3,006.0
Phenol	0.4	0.4
H ₂ S	44.9	40.8
HC	2.4	2.2
NH ₃	59.8	54.4

*Streams may not balance due to roundoff.

6.12.3.3 Control Equipment Specification and Cost Estimation

Effluent wastewaters from the phenol recovery process are directed to the wastewater treatment facilities; consequently, there are no pollution control measures which must be implemented here.

6.12.4. Sulfur Recovery

6.12.4.1 Process Description

Acid gas from the gas purification module contains approximately nine percent by volume hydrogen sulfide. It is feasible to convert the hydrogen sulfide gas to elemental sulfur, using the Stretford sulfur recovery auxiliary process.

The Stretford process is applicable to gases with a H₂S content no greater than 15 percent. Concentrations as low as 5-10 ppm H₂S can be achieved for industrial gases, using the Stretford process in combination with the high temperature hydrolysis recovery system (47).

In the process shown in Figure 46, feed gas passes through a packed absorber where H₂S is absorbed in the Stretford solution. The solution consists mainly of sodium metavanadate, sodium anthraquinone disulfonate (ADA), sodium carbonate, and sodium bicarbonate in water. The absorbed H₂S is oxidized to elemental sulfur by the reduction of sodium metavanadate. The reduced vanadium compound is in turn oxidized by anthraquinone disulfonate. The ADA is regenerated by air oxidation in an oxidizer tank. Sulfur is floated to the surface as a froth and can be processed by either filtration or centrifugation. Filtrate and wash waters from sulfur separation are returned to the absorption unit.

About 400 percent excess air is used to facilitate oxidation and flotation. The overall process reaction is described below (47):



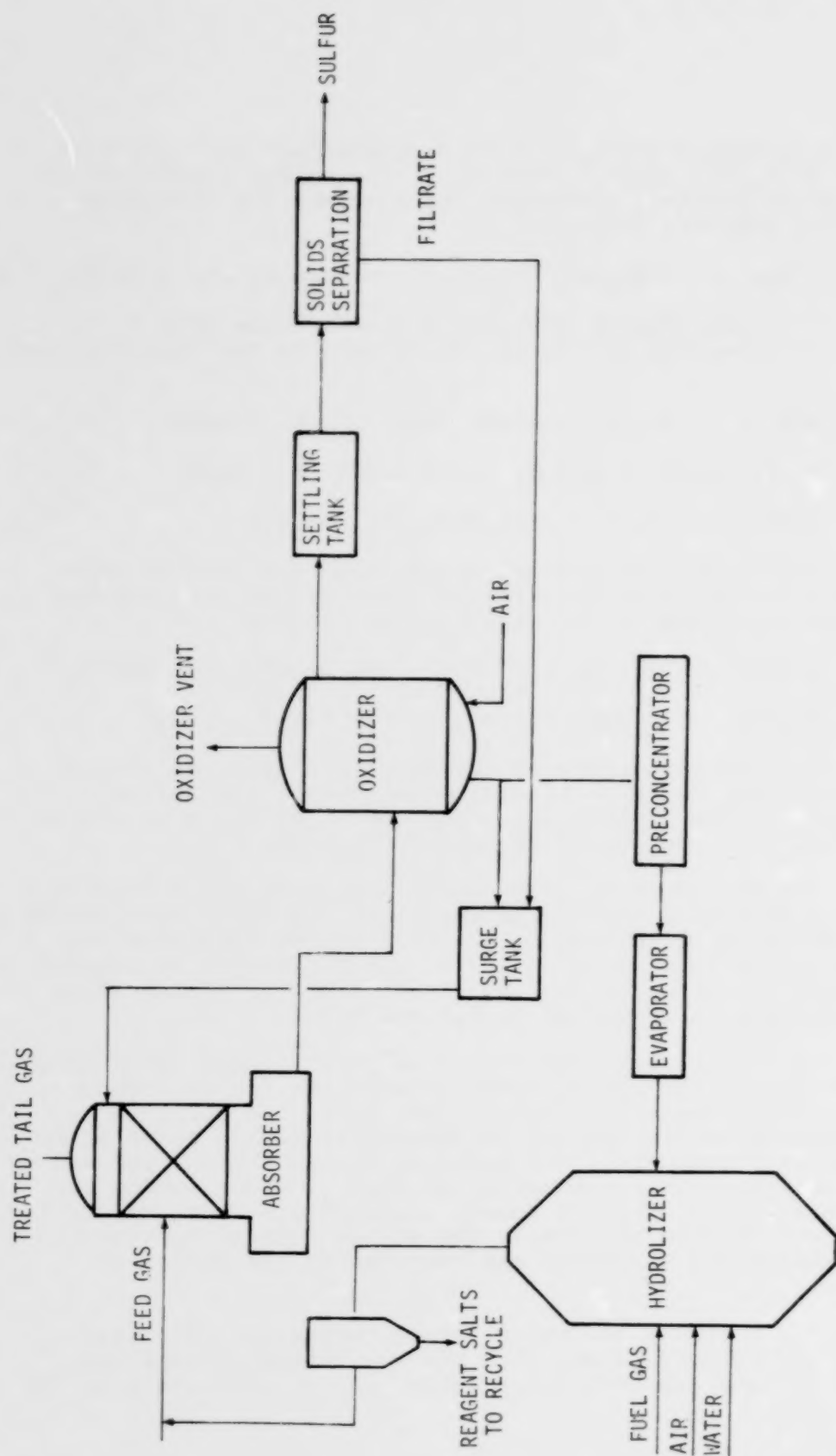


Figure 46. Stretford Sulfur Recovery With High Temperature Hydrolysis

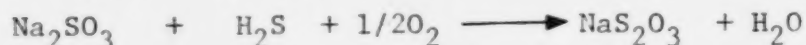
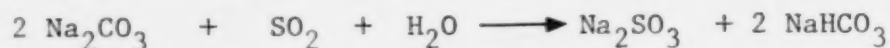
A properly designed Stretford absorber and oxidizing tank will lose about 1 percent of its sulfur production to sodium thiosulfate formation, as shown by the following overall reaction (47):



Hydrogen cyanide present in the feed gas will be completely converted to sodium thiocyanate in the following manner:



Sulfur dioxide present in the feed gas will be converted to sodium sulfite in the absorber and oxidized to thiosulfate form in the oxidizer, as follows:



Continuous purging of the Stretford solution stream prevents the build-up of sodium thiocyanate and sodium thiosulfate to the crystallization point. The purge stream has a total salt content of 20-25 percent (47).

The Stretford solution purge stream is decomposed by a high temperature hydrolysis technique, in which vanadium is recovered in solid form, along with sodium carbonate and some sodium sulfide and sulfate. Hydrogen cyanide is completely converted to CO_2 , H_2O , and nitrogen, while sodium thiosulfate is converted to H_2S and water.

In the process, the liquid is first concentrated in an evaporator. The concentrated solution is fed to a cocurrent, high temperature hydrolyzer, where the solution is evaporated to dryness and decomposed in a high temperature reducing atmosphere. The reducing atmosphere is produced by the stoichiometric combustion of fuel. Gases leaving the process are cycloned to remove recyclable solids and are fed to the Stretford absorber. The solids containing vanadium and sodium are dissolved and recycled to the Stretford plant.

The nitrogen and water formed during the hydrolysis step are recycled along with the gas stream through the absorber and are eventually vented to the atmosphere in the tail gas.

6.12.4.2 Process and Waste Streams

Process and waste streams entering or leaving the Stretford unit are shown in Figure 47. Stream compositions are shown in Table 56. The Stretford process, when coupled with high temperature hydrolysis recovery, yields one major waste stream, i.e. the off-gas from the absorber. This off-gas will contain mostly water, carbon dioxide, oxygen, and nitrogen with trace amounts of hydrogen sulfide, carbon monoxide, ammonia, and NO_x . The oxidizer vent gas is the only other emission from the unit; it consists of air and water vapor.

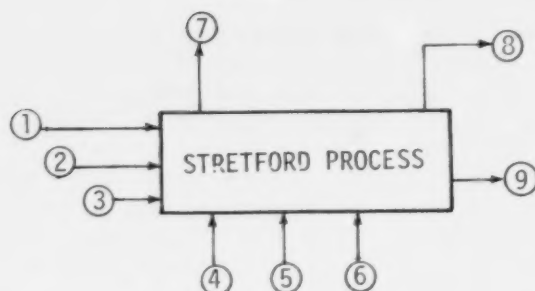
6.12.4.3 Control Equipment Specification and Cost Estimation

The Stretford sulfur recovery unit generates a large gaseous waste stream (1,2172 TPD or 1,1065 Mg/day) containing light hydrocarbons, hydrogen sulfide, carbon monoxide, nitrogen oxides, and ammonia. Concentrations of gaseous components can be found in Table 57. The major pollutant in the Stretford tail gas consists of the light hydrocarbon component, which is present at a concentration of 5,536 ppm by volume. Illinois standards for petrochemical plants require that hydrocarbon concentrations are less than 100 ppm; therefore, some form of hydrocarbon removal is required. Concentrations of H_2S (10.2 ppm) and carbon monoxide (143 ppm) are compatible with existing New Mexico standards for H_2S emissions from coal gasification plants (10 ppm) and below Illinois regulations for petrochemical plants (200 ppm), respectively. Nitrous oxides and ammonia are present in significant concentrations and may require pollution control technology.

Feasible alternatives for hydrocarbon control include direct flame incineration and carbon adsorption systems. Condensation systems are only used when vapor concentrations are high, and are therefore not applicable for Stretford tail gas treatment. As mentioned earlier, catalytic incineration is not believed to have an adequate hydrocarbon removal efficiency.

Table 58 presents cost data, removal efficiencies, emissions, and secondary wastes for direct flame incineration and carbon adsorption systems. It is apparent that carbon adsorption does not meet the Illinois standards for hydrocarbon emissions, and can no longer be considered a feasible treatment alternative.

SULFUR RECOVERY



STREAM	QUANTITY*	
	(TPD)	(Mg/day)
1 Gas from gas purification	775	705
2 Gas from hydrogen production	6503	5912
3 Water	81	74
4 Air (for oxidation)	53040	4822
5 Fuel gas	9	8
6 Air with fuel gas	169	154
7 Effluent gas	12077	10979
8 Sulfur	488	444
9 Flue gas	169	154

*Streams may not balance due to roundoff

Figure 47. Process and Waste Streams In The Sulfur Recovery System

TABLE 56. SULFUR RECOVERY STREAM COMPOSITIONS

Stream	Quantity*	
	(TPD)	(Mg/day)
1. Gas from Gas Purification		
H ₂ S	422.4	384.0
H ₂ O	11.0	10.0
HC	56.0	50.9
CO	1.4	1.3
CO ₂	284.4	258.5
2. Gas from Hydrogen Production		
H ₂ S	96.2	87.5
CO ₂	6,270.0	5,700.0
HCN	1.5	1.4
SO ₂	0.2	0.2
NO	0.006	0.006
NH ₃	0.7	0.7
Ash	4.4	4.0
Argon	6.1	
5. Fuel Gas and Air		
Fuel Gas		
N ₂	0.07	0.07
CO	1.2	1.0
CO ₂	0.01	0.01
CH ₄	4.6	4.2
C ₂ H ₆	2.9	2.6
Air	160.3	145.7
7. Effluent Gas		
H ₂ S	0.1	0.1
HC	56.0	50.9
CO	1.4	1.3
CO ₂	6,556.8	5,960.0
N ₂	4,085.1	3,713.7
O ₂	974.1	885.5
NC	0.006	0.006
NH ₃	0.7	0.7
H ₂ O	366.9	333.5
Ar	36.1	32.8

TABLE 56. SULFUR RECOVERY STREAM COMPOSITIONS

(Continued)

Stream	Quantity*	
	(TPD)	(Mg/day)
9. Flue Gas		
Ash	4.4	4.0
N ₂	127.1	115.5
CO ₂	23.6	21.5
O ₂	7.7	7.0
H ₂ O	10.6	9.6

*Streams may not balance due to roundoff.

TABLE 57. COMPONENTS IN STRETFORD TAIL GAS

COMPONENT	g-moles/day	Concentration
N ₂	1.32×10^8	41.9%
CO ₂	1.35×10^8	42.7%
O ₂	2.76×10^7	8.7%
H ₂ O	1.85×10^7	5.8%
Hydrocarbons (as ethane)	1.75×10^6	5,536 ppm
Argon	8.20×10^5	3,000 ppm
NH ₃	3.54×10^4	112 ppm
CO	4.54×10^4	143 ppm
H ₂ S	3.27×10^3	10 ppm
NO _x (as NO)	1.82×10^2	0.6 ppm

TABLE 58. HYDROCARBON TREATMENT ALTERNATIVES FOR STRETFORD TAIL GAS (48,49)

Basis: 173,900 scfm (82.1 m³/sec)
hydrocarbon conc. = 5,536 ppm (as ethane)

Treatment	Capital Cost (\$1000)	Operating Cost (Annual) (\$1000)	Efficiency	Emission After Treatment (98%)	Secondary Waste
Direct-Flame Incineration	572	4,083	98+%	H ₂ S 0.2 ppm SO ₂ 17.7 ppm HG 79.0 ppm NO 96.6 ppm CO 2.5 ppm CO ₂ 43.6 % NH ₃ 2.0 ppm	Water and carbon dioxide from com- bustion.
Carbon Adsorption with Incineration (AdSox)	1,843	3,546	up to 99%	H ₂ S = 9.5 ppm *HC = 278 ppm CO ₂ = 42.9 ppm CO = 12.7 ppm NO = 0.6 ppm NH ₃ = 111 ppm	Water and carbon dioxide from in- cineration

*Exceeds Illinois Standard

6.12.5 Oxygen Generation

6.12.5.1 Process Description

The hydrogen production process used in a SRC plant to produce make-up hydrogen for the hydrogenation reactors, requires large quantities of oxygen which must be produced on site. A cryogenic air separation system, consisting of air compression, cooling, and purification, air separation by distillation, and oxygen compression, is normally used to produce the required volume of oxygen. Figure 48 depicts a conventional air separation system (50).

In a conventional cryogenic air separation system, air is introduced into a four stage compression chamber which compresses the air to approximately 2940 psig (20.3 MPa) (50). The gas is cooled between each compression stage and condensed water is removed. The compressed gas passes through a water quench tower and reversible heat exchanger where the gas is cooled and contaminants are deposited within the exchanger. The gas is then further cooled to about -30°C by ammonia refrigeration (50). The cooled gas enters the combined liquefier-distillation chamber where the temperature is decreased to -191°C and the liquid oxygen and nitrogen separated (50). The products are returned to the heat exchanger. Nitrogen is discharged as a waste product along with trace contaminants such as CO_2 , argon, xenon, radon, krypton, oxygen, and water. The purified oxygen is compressed, cooled, and forwarded to the gasifiers.

Studies have indicated that about 1.5 tons (1.4 Mg) of oxygen must be provided per ton of carbon and hydrogen processed in the gasifiers (30). Based on this factor and 3,000 tons per day (2727 Mg) of coal and residue containing 61 percent carbon and hydrogen, approximately 2,745 tons (2,495 Mg) of oxygen must be separated per day.

6.12.5.2 Process and Waste Streams

Influent and effluent process and waste streams are shown in Figure 49. Stream constituents are given in Table 59.

Only one waste stream, containing mostly nitrogen, is discharged as a result of oxygen production processes. Based on an oxygen demand of 2,745 TPD (2495 Mg/day), this waste stream amounts to approximately 9,997 TPD (9,088 Mg/day).

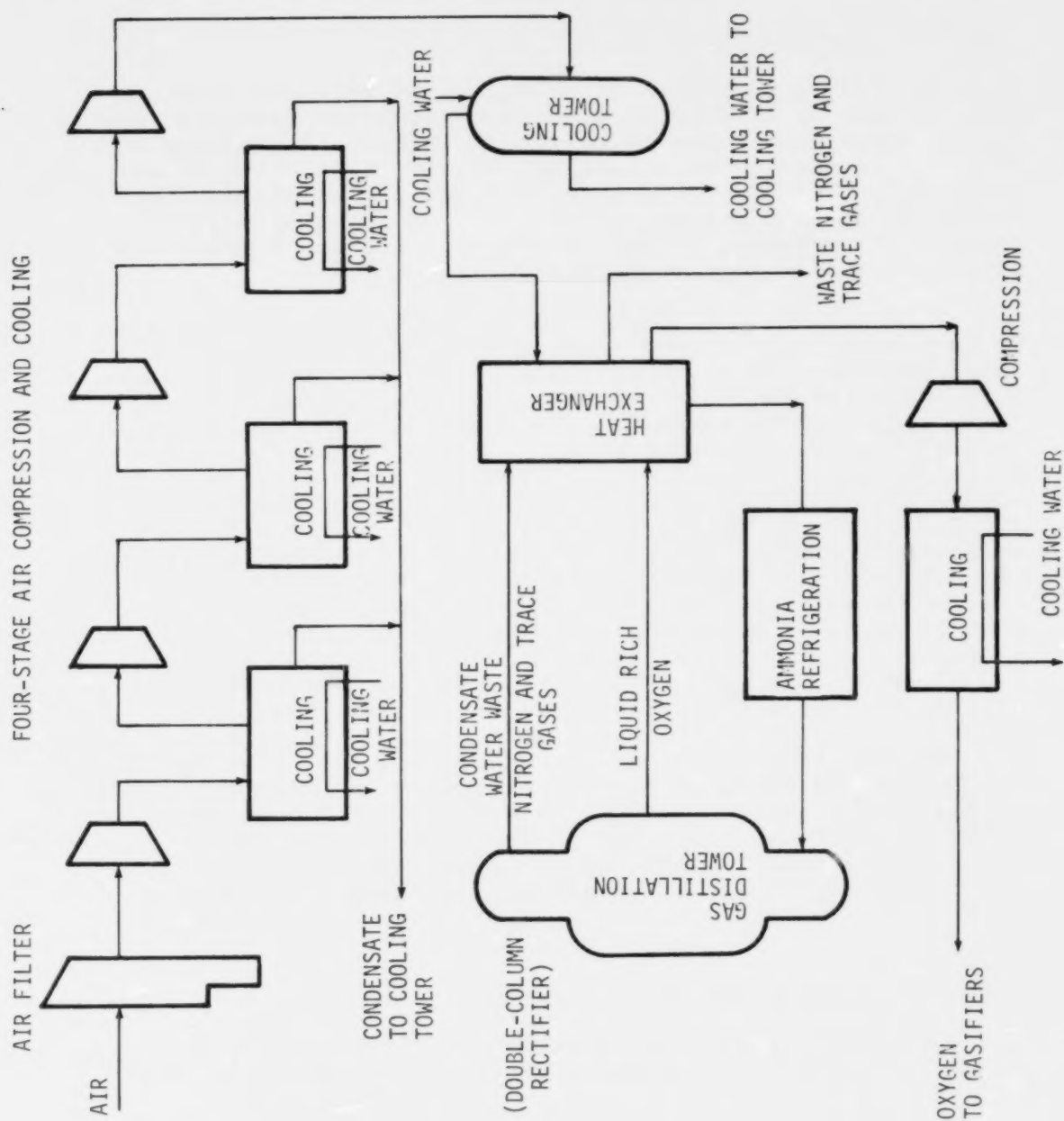
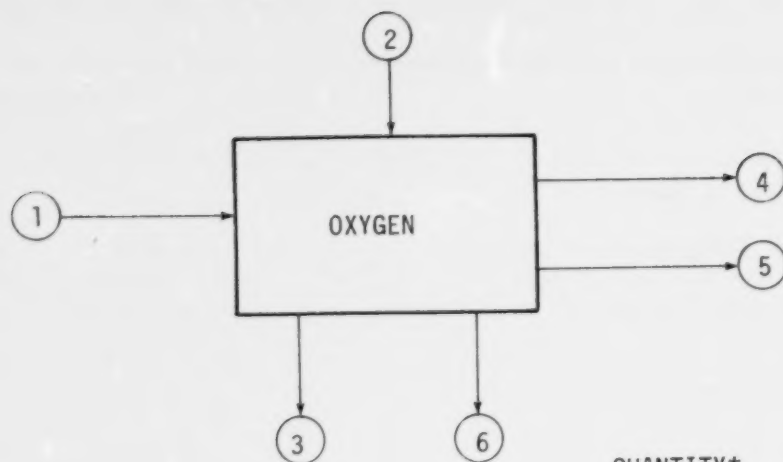


Figure 48. Oxygen Generation



<u>STREAM</u>	<u>QUANTITY*</u>	
	<u>(TPD)</u>	<u>(Mg/day)</u>
1. Air (50% humidity, 60°F)	12815	11650
2. Cooling water	16404	14913
3. Condensate water	12	11
4. Product gas	2806	2551
5. Waste nitrogen stream	9997	9088
6. Cooling water out	16404	14913

*Streams may not balance due to roundoff.

Figure 49. Oxygen Generation

TABLE 59. OXYGEN GENERATION PROCESS AND WASTE STREAMS

Stream	Quantity*	
	(TPD)	(Mg/day)
2. Cooling Water		
Air Compression Stages	9,004.0	8,185.4
Water Quench Tower	5,424.0	4,930.9
Oxygen Compression Stage	1,976.0	1,796.4
4. Product Gas		
Oxygen	2,745.0	2,495.0
Argon	36.1	32.8
Nitrogen	25.2	22.9
3. Waste Nitrogen Stream		
Nitrogen	9,601.8	8,728.9
Argon	129.3	117.5
Carbon Dioxide	6.4	5.8
Hydrogen	1.3	1.2
Neon, Xenon, Krypton	6.4	5.8
Water	52.06	47.3
Oxygen	200.0	181.8

*Streams may not balance due to roundoff.

6.12.5.3 Control Equipment Specification and Cost Estimation

Since the waste nitrogen stream discharged from the oxygen plant contains only natural components of air, there are no control measures which must be applied to this stream. Of the 12,815 tons (11,650 Mg) of air which must be processed daily, approximately 9,997 tons per day (9,088 Mg/day) are returned to the environment.

6.12.6 Raw Water Treatment

6.12.6.1 Process Description

A continuous supply of water is needed in the liquefaction process for makeup water in the cooling towers and for boiler feedwater softening and demineralization operations. It is also needed in the waste disposal treatment facilities and as a general supply of potable, fire, and domestic water. Water usage is dependent upon the size of the plant, housekeeping practices, process operations, and pollution control technologies. A typical raw water treatment process is shown in Figure 50 (24). Characteristics of raw water taken from the Wabash River are given in Table 60.

Raw water is usually pumped to a treatment plant after being screened to remove large debris. Chemicals are then added to the raw water in a rapid mix chamber as aids in settling out suspended matter and heavy metals in subsequent flocculation, sedimentation, and filtration unit operations. Softening agents are also added in the rapid mix chamber. The water usually drains from the sand filters to a clear well where it is lifted to a raw water storage tank. Water is pumped from the storage tank to the cooling towers and potable water storage area as needed. Chlorination injection facilities are located on the outlet end of the raw water storage tank pumps.

6.12.6.2 Process and Waste Streams

Process and waste streams are shown in Figure 51. Stream constituents are given in Table 61.

The major waste stream discharged from the raw water treatment facility is sludge removed from the clarifiers. This sludge contains metal complexes, carbonate compounds, suspended solids, and other trace compounds which were present in the raw water.

Sand filter filtrate is expected to be returned to the clarifier.

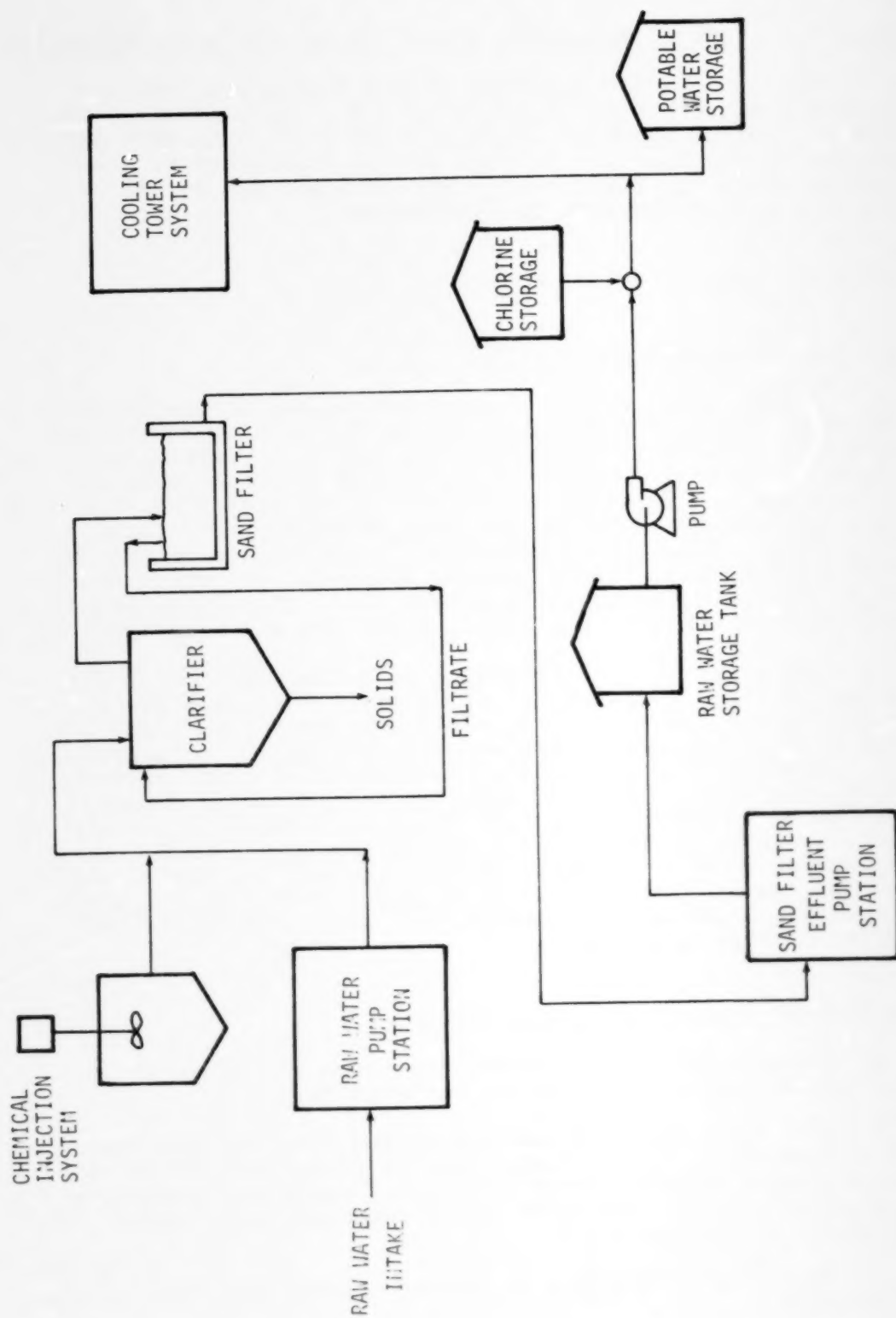
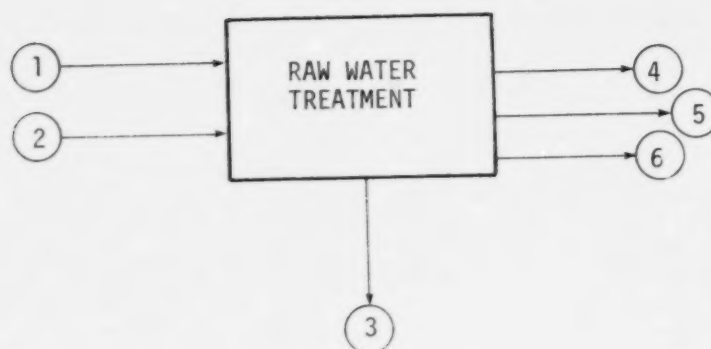


Figure 50. Raw Water Treatment

TABLE 60. TYPICAL CONSTITUENTS IN WHITE COUNTY, ILLINOIS
RAW WATER SUPPLY

Parameter	Range (mg/l)	Ave. (mg/l)
Specific Conductance (umhos)	207-794	535
Temp (°F)	34-86	61
pH (units)	68-74	7.6
Calcium	29-94	66.5
Magnesium	16-32	24
Bicarbonate	110-228	199
Carbonate	0	0
Sulfate	36-180	83
Chloride	8-42	25
Fluoride	0.2-0.4	0.3
Nitrate	0.6-24	12.3
Phosphorous	0.21-1.3	0.75
Dissolved Solids (Residue at 180°C)	201-508	355
Hardness as CaCO ₃ :		
Calcium, Magnesium	134-350	242
Non-Carbonate	44-153	97
Detergent (MBAS)	0.0-0.1	0.1
Suspended Solids		40



<u>STREAM</u>	<u>QUANTITY*</u>	
	<u>(TPD)</u>	<u>(Mg/day)</u>
1. Raw Water Input	35,263	32,057
2. Chemicals	15	14
3. Sludge (5% solids)	407	370
4. Cooling Tower Water	25,401	23,092
5. Direct Water Use In Plant	4,331	3,937
6. Water Used For Steam Production	5,145	4,677

*Quantity of water needed in operations (does not include weight of contaminants present in water).

Figure 51. Raw Water Treatment Process and Waste Streams

TABLE 61. RAW WATER TREATMENT STREAM COMPOSITIONS

Stream		Quantity*	
1.	Raw water input (avg. conc)	(mg/l)	
	Illinois Area		
	Specific conductance (umhos)	535.0	
	Temperature (°F)	61.0	
	pH	7.6	
	Ca	66.5	
	Mg	24.0	
	HCO ₃	199.0	
	SO ₄	83.0	
	Cl	25.0	
	Fluoride	0.3	
	NO ₃	12.3	
	PO ₄	0.8	
	Detergent	0.1	
	Suspended solids	40.0	
2.	Chemicals	(TPD)	(Mg/day)
	Lime	7.6	6.9
	Na ₂ CO ₃	7.7	7.0
3.	Sludge	(TPD)	(Mg/day)
	Water	386.8	351.6
	CaCO ₃	17.6	16.0
	Mg(OH) ₂	1.0	0.9
	Ca ₅ (OH)(PO ₄) ₃	0.04	0.04
	Detergent	0.0003	0.00003
	Suspended Solids	1.4	1.3
4.	Cooling Tower Water	(mg/l)	
	Ca	12.0	
	Mg	12.2	
	SO ₄	83.0	
	Cl	25.0	
	Fluoride	0.3	
	NO ₃	12.3	
	PO ₄	0.08	
	Water	25,401.3*	(23,092.1)
	Na	82.6	

*Units in TPD as noted

** Streams may not balance due to roundoff.

6.12.6.3 Control Equipment Specification and Cost Estimation

The main waste stream discharged from the raw water treatment facilities is sludge from the clarifiers. Considering the diluted sludge which is withdrawn from the clarifiers (approximately 5 percent), it is economically essential to remove some of the moisture from the sludge prior to trucking it to a landfill. It may also be economically feasible to recover lime from the sludge after it is dewatered.

Various sludge dewatering methods are discussed in Chapter 5 under solid waste disposal. It was indicated that sludge dewatering equipment is capable of reducing the moisture content of sludges from 95 to 40 percent. An analysis of sludge dewatering followed by sludge transport Vs. wet sludge transport is necessary to determine which method is most cost effective.

Recalcination of lime sludges may prove to be more effective than dewatering processes, considering the cost of chemicals and sludge transport. This process not only recovers valuable chemicals but also reduces the moisture content of the sludge by a factor of 10, much greater than the moisture reduction provided by dewatering equipment.

Costs of lime sludge disposal alternatives are given in Table 62. Alternative II appears to be more cost effective.

6.12.7 Cooling Water System

6.12.7.1 Process Description

Cooling water, an essential component of a coal liquefaction plant, is continuously needed to cool reactor vessels within the plant and to cool directly various process streams. Cooling towers maintain a continuous supply of cooling water. In addition to the basic cooling tower structure, piping, and other appurtenances, water treatment facilities are also essential components of the cooling tower system since the effective operation of towers can only be maintained by recirculating relatively clean water. A flow diagram of a typical cooling tower system is shown in Figure 52 (52).

Cooling water is directed from the cooling tower through closed piping to plant heat exchangers. Before recirculation back to the cooling tower, a portion of the cooling water is directed through a sidestream treatment operation (blowdown). This is incorporated into the process to maintain a constant

TABLE 62. LIME SLUDGE DISPOSAL (14,51)

Process	Costs	
	Capital (\$1,000)	Operating (Annual) (\$1,000)
<u>Alternative I</u>		
Lime recalcination	890 (1977)	108.96 (1967)
Sludge transport (5.4 TPD)	-	5.913 (1977)
Sludge landfill (5.4 TPD)	-	11.826 (1977)
Savings on lime costs (by recovery based on lime costs of \$40/ton)	-	110.67 (1977)
<u>Alternative II</u>		
Cost of lime (\$40/ton)	60.0	110.67 (1977)
Thickener (20% solids out) 100 TPD	60.9	Cost of Chemicals N/A
Centrifuge (60% solids out) (53.3 TPD)	60.0	Cost of power N/A
Sludge transport	-	58.4
Sludge landfill (53.3 TPD)	-	116.7

N.A. = Not Available

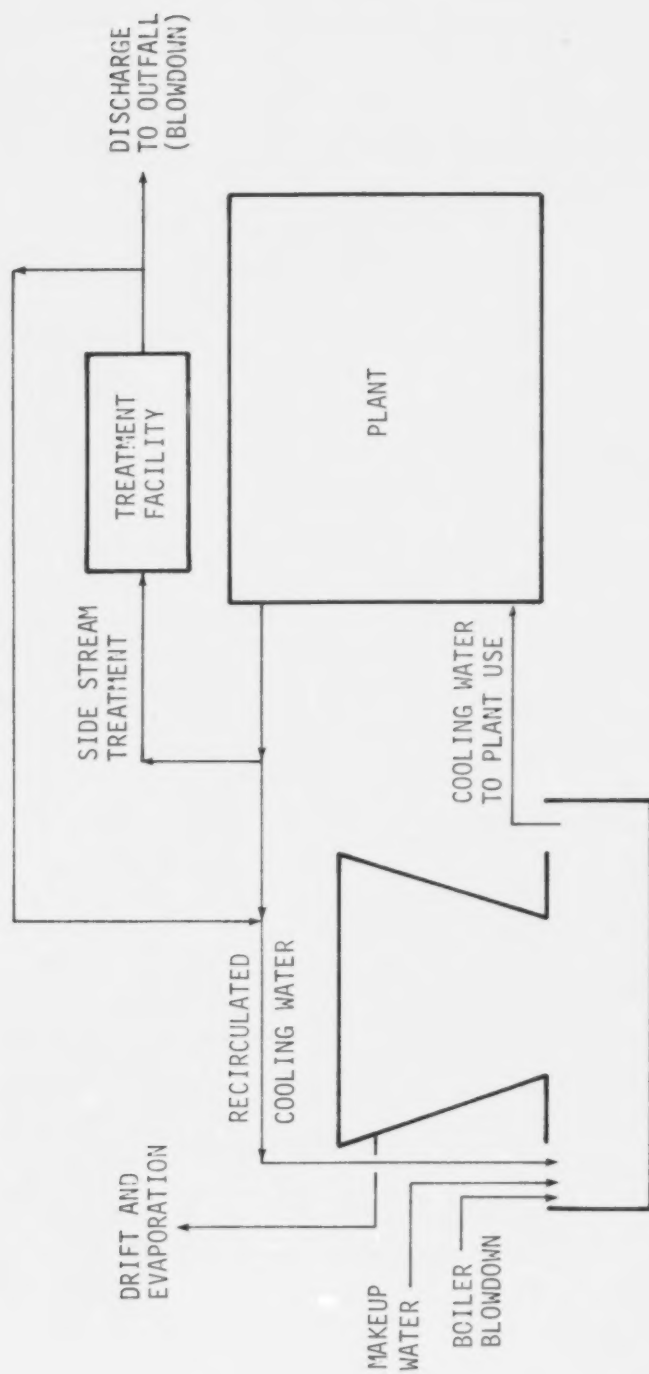


Figure 52. Plant Cooling Water System

level of dissolved solids in the recirculating cooling water stream. With sidestream treatment, typical blowdown rates are 3-5 percent of the makeup water rate (52). Sidestream treatment facilities commonly used are reverse osmosis, electrodialysis, or ion exchange. The wastewater from the treatment process is generally discharged to the river. Raw water is added to the cooling tower influent as makeup water to replace the water lost by heat dissipation (evaporation) in the cooling towers, by cooling tower blowdown, and by leakage. Evaporation represents the most significant source of cooling water lost in the system.

6.12.7.2 Process and Waste Streams

Process and waste streams are shown in Figure 53.

The main waste stream discharged from the cooling towers is blowdown containing suspended solids, dissolved solids, chromium, and other trace metals. This stream is treated by ion exchange, electrodialysis, or reverse osmosis and discharged to the receiving stream. Regeneration wastewaters from this operation are disposed of off-site.

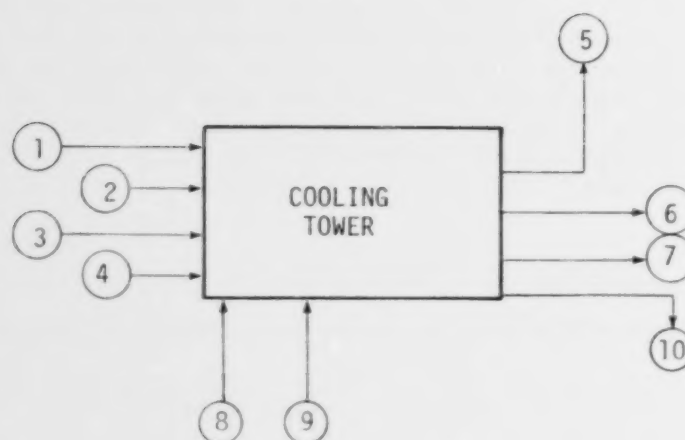
Cooling tower drift and evaporation represent possible contaminant discharges to the atmosphere. This amounts to approximately 24,529 TPD (22,299 Mg/day).

6.12.7.3 Control Equipment Specification and Cost Estimation

There are two environmental discharges resulting from the operation of the cooling towers: drift and evaporation and blowdown.

No control measures can be undertaken to control drift and evaporation from the cooling towers except through the initial design of the towers. The concentration of chemicals which may be discharged with the drift and evaporation may, however, be controlled by varying the rate of blowdown and/or by increasing the degree of raw water treatment. Since the option of increasing raw water quality has not been included in this report, only the former control method can be implemented. Cooling tower drift and evaporation amounts to approximately 24,529 TPD (22,299 Mg/day).

A portion of the circulating cooling water is continuously purged in order to maintain a dissolved solids level of about 50,000 ppm. The purge stream or blowdown is normally discharged directly to the river from a cooling tower side stream treatment system such as ion exchange, reverse osmosis, or lime softening. Controls are not usually applied to this discharge. For the model SRC plant, approximately 762 TPD (693 Mg/day) of blowdown is discharged to the river.



STREAM	QUANTITY*	
	(TPD)	(Mg/day)
1. Makeup water	25,401	23,092
2. Boiler blowdown	15	14
3. Recirculated water	1,260,000	1,145,455
4. Chlorine and chromates	NOT QUANTIFIED	
5. Drift and evaporation	24,529	22,299
6. Cooling water	1,260,000	1,145,455
7. Side stream treatment (Blowdown)	762	693
8. Recycle water from slag clarifier in hydrogen production	269	245
9. Recycle water from treatment plant	5,075	4,614
10. Water to plant use	5,469	4,972

*Streams may not balance due to roundoff.

Figure 53. Cooling Water Process and Waste Streams

6.12.8 Steam and Power Generation

6.12.8.1 Process Description

Steam and electric power are usually generated on-site in order to make a coal liquefaction plant self-sufficient. There may be times, however, when it is more cost effective to purchase the required power off-site than to produce it. In this model, it is assumed that power will be purchased. This significantly reduces the on-site coal consumption, cooling water requirements, and gaseous emissions to the environment. It is estimated that about 110 MW are required for a 20,000 ton per day (18,182 Mg/day) SRC plant (23).

The quantity of steam which must be produced on-site is dependent upon the volume of steam produced by various processes and the volume of steam which is consumed.

Steam may be produced indirectly in waste heat boilers located throughout the plant. This reduces the volume of steam which must be produced and provides a means of cooling hot effluents from various unit operations. Usually 600 psig steam (4.1 MPa) is produced in coal-fired boilers to fulfill the plant steam requirements (23).

Most steam produced in the plant is recycled to the boilers in a closed conduit for reuse. In some instances, however, steam is introduced directly into reactor vessels where it becomes part of the process stream. Makeup water, therefore, must be continuously added to the steam generating facilities.

Typical steam generation facilities are shown in Figure 54 (23). Since boiler water must be of high purity, raw makeup water is demineralized prior to entering the boiler water circuit. In order to maintain relatively low concentrations of dissolved solids in the circuit, a blowdown stream also is continuously discharged. This stream is directed to the cooling tower system. Blowdown rates are approximately 0.1 to 1.0 percent of the steam flow (52).

6.12.8.2 Process and Waste Streams

Process and waste streams are shown in Figure 55.

Stream compositions are given in Table 63.

Flue gas is the most significant discharge from the boilers, amounting to about 13,145 TPD (11,950 Mg/day). This gas must be cleaned before being discharged to the environment. A smaller waste stream discharged from the steam generation facilities is ash from the boilers. Ash

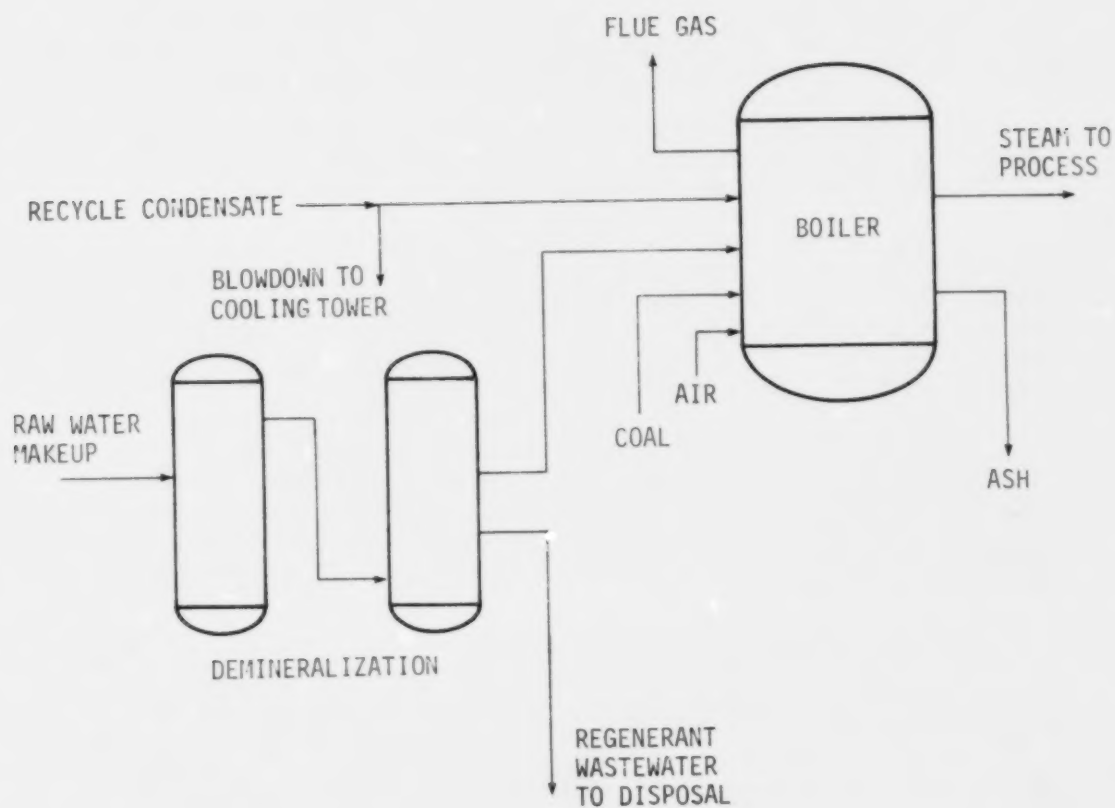
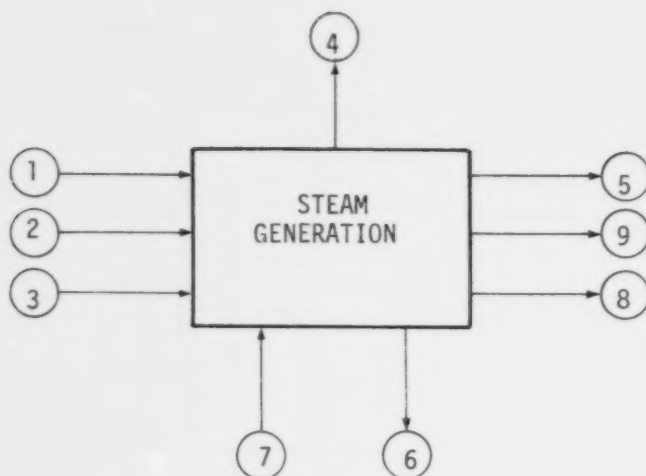


Figure 54. Steam Generation Facilities



STREAM	QUANTITY*	
	(TPD)	(Mg/day)
1. Recycled water	14680	13345
2. Makeup water	5145	4677
3. Coal	1024	929
4. Stack gas	13145	11950
5. Steam	19810	18009
6. Ash	73	66
7. Air	12195	11087
8. Boiler blowdown to cooling tower	15	14
9. Waste from demineralization operations	NOT QUANTIFIED	

*Streams may not balance due to roundoff

Figure 55. Steam and Power Generation Process and Waste Streams

TABLE 63. STEAM AND POWER GENERATION STREAM COMPOSITIONS

<u>Stream</u>	<u>Quantity*</u>	
	(TPD)	(Mg/day)
4. Stack Gas		
CO ₂	2554.7	2322.5
H ₂ O	451.5	410.5
SO ₂	69.7	63.3
O ₂	656.7	597.0
N ₂	9362.7	8511.6
NO _x	9.2	8.4
CO	0.5	0.5
HC	0.2	0.1
particulates	40.3	36.6

*Streams may not balance due to roundoff.

is discharged at a rate of 73.0 TPD (66.0 Mg/day). Boiler blowdown is directed to the cooling towers.

6.12.8.3 Control Equipment Specification and Cost Estimation

The combustion of coal for steam and power generation results in one of the major atmospheric pollutant streams in a SRC facility. A component analysis of the boiler flue gas can be found in Table 64.

Principal pollutants include SO₂ (2465 ppm), NO_x (6946 ppm as NO), particulates (1.77 grains/scf.), and carbon monoxide (45.2 ppm).

Illinois emission standards for coal-fired boilers require that pollutant concentrations do not exceed the following levels (53):

- Sulfur Dioxide - 1.2 lb/MM Btu coal. Total allowable daily emissions are 16 tons (14.5 Mg/day), based on coal consumption of 1022 TPD (929.1 Mg/day) at 12,820 Btu/lb.
- Nitrogen Oxides - 0.7 lb/MM Btu coal. Total allowable daily emissions are 9 tons (8.2 Mg/day).
- Carbon Monoxide - 100 ppm based on 50% excess air. Concentration for 25% excess air has been calculated to be 125 ppm.

Illinois standards for particulates in the petrochemical plant require that not more than 1.0 TPD (0.9 Mg/day) be discharged. Coal-fired boilers may not have particulate emissions exceeding 0.5 TPD (0.5 Mg/day) (based on a coal consumption at 1022 TPD [929 Mg/day] at 12,820 Btu/lb). In Table 65, the removal efficiencies needed to meet existing regulations are presented, along with applicable control equipment.

Wet scrubbing techniques remove SO₂ and particulates simultaneously and therefore are judged to be the most feasible means of control. NO_x interferes with wet SO₂ scrubbing processes, and therefore should be controlled by combustion modification techniques. Table 66 presents removal efficiencies, capital and operating costs, and emissions after treatment for some commercially available wet scrubbing techniques. Because of a relative lack of data, no process could be singled out as the most efficient. Capital and operating costs for each process were very similar.

TABLE 64. CONSTITUENTS IN FLUE GAS FROM STEAM GENERATION

Total flow rate = 22,500 scfm (10.6 m³/sec)

Constituent	TPD*	Lb Moles/Day	Concentration
N ₂	9363.0	668,760	75.6%
CO ₂	2555.0	116,120	13.1%
H ₂ O	452.0	50,170	5.7%
O ₂	657.0	41,040	4.6%
NO _x (As NO)	9.0	6,140	0.7% (6946 ppm)
SO ₂	70.0	2,180	0.2% (2465 ppm)
Hydrocarbons (as ethane)	0.2	10	11.3 ppm
Particulates	40.0	--	1.77 grains/scf

*Only English units are provided due to space limitations.
Metric conversion factors are given in the Appendix.

TABLE 65. REQUIRED REMOVAL EFFICIENCIES TO MEET
ILLINOIS EMISSION STANDARDS FOR COAL-FIRED BOILERS

Constituent	Emission Before Treatment	Illinois Emission Std.	Required Removal Efficiency	Applicable Control Technology
SO ₂	69.7 TPD	15.6 TPD	77.61%	Wet Scrubbing
NO	9.2 TPD	9.1 TPD	2.0%	Wet Scrubbing Boiler Modification
Particulates	40.3 TPD	0.54 TPD	98.65%	Wet Scrubbing Electrostatic Precipitator
CO	0.5 TPD (45.2 ppm)	125 ppm	-	

*Only English units are provided due to space limitation. Metric conversion factors are given in Appendix A.

TABLE 66. COSTS, EFFICIENCIES, AND FINAL EMISSIONS FOR COMMERCIALY AVAILABLE SO₂ WET SCRUBBING PROCESSES (54)

Basis: Coal-fired boiler flue gas
 220,500 scfm (103.6 m³/sec) at 2465 ppm SO₂;
 6,946 ppm NO_x, and 1.77 grains/scf fly ash (245.0 gm/m³)

Process	Cost		Operating (Annual) (\$ Million)	Removal Efficiencies		Emissions After Treatment	
	Capital (\$ Million)			SO ₂	NO _x	SO ₂	NO _x
Lime Slurry Scrubbing	20.56		12.01	90%	99+%	6.97 TPD	0.70+ TPD
Soda-limestone Double-alkali	26.81		13.21	*	up to 99%	*	0.70 TPD
MgO Scrubbing (recovery)	29.04		13.14	90%	99.5%	6.97 TPD	0.35 TPD
Limestone Scrubbing	24.65		12.16	70-80%	99%	17.42 TPD	0.70 TPD
Potassium Sulfite-Bisulfite Scrubbing	27.53		11.89	90%	*	6.97 TPD	*
Wet activated charcoal absorption	*		*	80%	*	13.94 TPD	*

* Data Not Available

Unfortunately, no information whatsoever was found on NO_x removal efficiencies in SO₂ scrubbing processes. It is believed that quantities of NO_x (more than the 2% required) will be removed by most of the wet SO₂ processes. Lime and limestone slurries and MgO have been used as scrubbing solutions for NO_x pilot plant removal systems. As mentioned before, NO_x actually interferes with wet SO₂ regenerable processes. It converts sulfite to sulfate. The regeneration step is usually based on sulfite decomposition and is either not effective on sulfate or is effective only at added costs.

Dependence on the wet SO₂ removal process also for NO_x removal would mean a large nonregenerable sulfate purge stream. Proper control of NO_x should be done by combustion modification. Flue gas recirculation and two-stage combustion are the most applicable. No information on costs for the two alternatives could be found.

Generally, mist elimination will be required after wet scrubbing in order to meet stack opacity requirements. Most commercially available wet scrubbing systems have a mist elimination section within the apparatus and do not require additional equipment.

Particulate emission standards have not been met by two of the SO₂ removal processes (double-alkali and limestone scrubbing). MgO scrubbing with a removal efficiency of 99.5% has met requirements. Since the removal efficiency of lime slurry is more than 99%, it may meet emission standards for particulates. However, without a specific number for removal efficiency, no conclusion can be drawn.

6.12.9 Product/By-Product Storage

6.12.9.1 Process Description

There are a number of products and by-products stored on-site such as liquid petroleum gas, naphtha, SRC fuel oil, sulfur, ammonia and phenols. Pipeline gas is also produced but sent directly into a gas pipeline grid for distribution. Liquefied petroleum gas is normally stored and shipped in atmospheric pressurized tankage. All storage tanks have gas vents which return hydrocarbon vapors to the gas purification area. This system prevents hydrocarbon vapor leakage in the storage area. Solid SRC is stored in hoppers.

Various by-products such as sulfur, ammonia, and phenols are removed from process waste streams, purified, and also sent to storage. Ammonia and phenols are stored in tanks; sulfur is stored outdoors in piles.

6.12.9.2 Process and Waste Stream

A summary of the expected products and by-products is given in Table 67.

Waste discharges from the product/by-product storage area will generally result from spills, infrequent tank cleaning, and fugitive vapor losses. Sulfur dust may also be discharged to the environment from sulfur storage piles.

6.12.9.3 Control Equipment Specification and Cost Estimation

Emissions from product and by-product storage facilities include vapor leakage from tanks and transfer lines and particulate emissions from SRC storage. Vapor leakage can be controlled by following proper engineering practices as outlined in Chapter 5. Particulate emissions from SRC storage have not been quantified. Dust control equipment that would be applicable to SRC storage is similar to those options mentioned in Section 6.1.3. Because of the lack of information on dust quantities, equipment size and cost data could not be specified.

6.13 Wastewater Treatment Facilities

Liquid wastes are discharged from numerous process areas within a SRC-II liquefaction plant, including hydrogen production, gas purification, cryogenic separation, auxiliary facilities (i.e., cooling towers), hydrotreating, and phase (gas) separation. Prior to being directed to wastewater treatment facilities, several of the waste streams are sent to by-product recovery for the removal of ammonia, sulfur, and phenol. The by-product recovery step not only economically recovers various chemicals but also reduces the toxicity from phenols in the wastewaters, prevents odor problems, and eliminates the inclusion in the treatment facilities of costly equipment for the removal of nitrogen. Typical anticipated wastewater constituents include ammonia, hydrogen sulfide, phenols, organic compounds (oils), trace heavy metals, sulfates, organic nitrogen and sulfur, and alkalinity.

Table 68 lists two alternative methods of treating SRC process wastewaters to acceptable levels for plant reuse along with anticipated influent and effluent stream compositions. The treatment units common to both alternatives are presented first, followed by alternative biological treatment schemes. These alternatives were formulated, based on the following considerations:

TABLE 67. PRODUCT/BY-PRODUCT STORAGE

<u>Products</u>	<u>Quantity</u>	
	(TPD)	(Mg/day)
SNG	1434.1	1311.6
LPG	902.8	820.7
Naphtha	570.0	518.2
Fuel Oil	2850.0	2590.9
SRC	6080.0	5527.0
<u>By-Products</u>		
Phenol	37.40	34.0
Ammonia	70.3	63.9
Sulfur	486.5	442.3

TABLE 68. COMMON TREATMENT PROCESSES TO ALL ALTERNATIVE
TREATMENT DISPOSAL METHODS

Process	Common Units for Alternatives	Parameter (TPD)					
		NH ₃	H ₂ S	Phenol	SS	HC	Flow
							BOD
Stream Stripping of NH ₃ recovery wastes for removal of H ₂ S and NH ₃	in	0.7	54.7	0.8	0.0		4201.0
	out	0.2	0.2	0.5	0.0		4201.0
API Separator for stripped wastewater (for H ₂ S and NH ₃) and phenol recovery wastewater	in	0.2	.2	0.5	0.0	2.4	4201.0
	out	0.2	.2	0.5	0.0	1.9	4201.0
Equalization - Add sour water from hydrogen production to effluent from API Separator	in	0.2	.2	0.5	0.7	1.9	5079.0
	out	0.2	.2	0.5	0.7	1.9	5079.0
Dissolved Air Flotation API Separator	in	0.2	.2	0.5	0.7	1.9	5079.0
	out	0.2	.2	0.5	0.4	0.2	5079.0
<u>Alternative I</u>							
Biological Treatment Extended Aeration	in	0.2	.2	0.5	0.4	0.2	5079.0
	out	Trace	Trace	0.03	0.2	0.01	5079.0
Filtration	in	Trace	Trace	0.03	0.2	0.01	5079.0
	out	Trace	Trace	0.03	0.1	0.01	5079.0
<u>Alternative II</u>							
Biological Treatment Aerated Lagoon	in	0.2	.2	0.5	0.4	0.2	5075.0
	out	Trace	Trace	0.03	0.2	0.01	5075.0
Settling Basin	in	Trace	Trace	0.03	0.2	0.01	5075.0
	out	Trace	Trace	0.03	0.1	0.01	5075.0

- It is more cost effective to segregate and treat individual waste streams when specific stream components must be removed (i.e., oils and hydrogen sulfide).
- Influent suspended solids were not high enough to warrant inclusion of suspended solids removal equipment.
- Neutralization of wastewaters may be effected most satisfactorily by the mixing of various waste streams in an equalization basin.
- Selection of biological treatment systems was based on required performance and reliability.
- The treated wastewater effluent is acceptable for reuse without further treatment.

Table 69 includes costs for the alternatives listed in Table 68. Alternative 1 appears to be more cost effective.

The treatment schemes listed in Table 68 have been extensively used in the petroleum industry for wastewaters containing oils and grease, hydrogen sulfide, ammonia, phenols, and suspended solids. Coal liquefaction publications to date have also indicated that these treatment units are expected to be employed in commercial facilities when built. At present, the Fort Lewis SRC pilot plant wastewater treatment facilities consist of a surge reservoir, waste disposal treater and flottazur (physical-chemical treatment), a biological treatment system, sand filter, carbon filter, and incinerator. The sand filter and carbon filter are needed at this plant because the wastewater is discharged into a "no-discharge" pond.

The physical-chemical treatment process is provided to remove suspended solids. These are included in this report because suspended solids are expected in wastewater from the dissolved air flotation unit and the biological treatment processes. The sand and carbon filters are not necessary when the effluent is recycled to the cooling tower for plant reuse. Fort Lewis pilot plant effluents have been observed to be better and/or equal to the limits specified in Table 70.

TABLE 69. COSTS OF TREATMENT PROCESSES

Based on Wastewater flow = 1.23 MGD		
PROCESSES	COSTS	
Common Units for Alternatives	Capital (\$1000)	Operating (Annual) (\$1000)
Steam Stripping	480.0	81.654
API Separator (3703 gallons)	69.0	1.0
Equalization Basin Aerators (.86 HP) and Basin (.0129 MG)	60.0	0.163
Dissolved Air Flotation Flotation Unit (Rectangular 4376 Gallons) Chemicals	90.0 N/A	14.0 N/A
Alternative I		17.4 (TOTAL)
Extended Aeration		
Basin (1.23 MG)	62.0	---
Air (diffused-5400 cfm)	100.0	---
Clarifier (.31 MG)	50.0	2.263
Chemicals (Phosphorus)	----	---
Installation	100.0	---
Filtration Options		
Pressure	87.5	4.083
Gravity (upflow)	104.5	---
Alternative II		67.12 (TOTAL)
Aerated Lagoon		
Basin (6.15 MG) and Aerators (411 HP)	813.0	2.263
Chemicals (Phosphorus)	----	----
Settler (.31 MG)	88.0	----

TABLE 70. FORT LEWIS PILOT PLANT EFFLUENT LIMIT (36)

Parameter	Quantity (mg/l)
pH	6.0-8.5
BOD ₅	40
COD	150
SS	50
phenol	0.5
oil and grease	10
sulfates	235

Solids wastes, in the form of excess activated sludge, also may be discharged from the treatment facilities periodically. This sludge is normally trucked to a suitable disposal site.

6.14 Flare Systems

SRC production, like petroleum refining and chemical processing industries, must dispose of small quantities of continuous hydrocarbon waste gas streams from the process units such as the hydrogenation reactor, flash drum separators and the fractionation column. In case of accidental release due to equipment failure, large flows of gases must be disposed. The common practice of disposal is the use of a flare. Elevated combustion flare systems will be most applicable for the liquefaction plant, since large gas flows are involved. Air inspiration with steam will be utilized to achieve smokeless combustion (1).

Combustion in smokeless elevated flares is essentially complete with the CO₂ to CO to hydrocarbon ratio of stack gas being 100:4:0.002. On a dry basis, carbon monoxide levels would be 4,000 ppm and hydrocarbon levels would be only 2 ppm (59).

The amount of gases to be flared and the composition of these gases can be assumed to be that of a refinery processing 50,000 bbl/day (7,950 m³/day) of oil. The stack height will be in the range of 33 to 100 meters depending upon the

location of the plant and meteorological conditions (1). Also, the amount of the duct work required will depend on the flare system distance from the processing units. These factors will affect the cost of the flare system. Steam, if not available from the process plant, will add to the operating cost.

Elevated flare system costs vary considerably because of the disproportionate costs for auxiliary and control equipment and the relatively low cost of the flare stack and burner. As a result, equipment costs are rarely diameter-dependent. Typical installed costs for elevated flares range from \$30,000-\$100,000. Operating costs are determined chiefly by fuel costs for purge gas and pilot burners, and by steam required for smokeless flaring. On the basis of 30 cents per million Btu's fuel requirement, typical elevated stack operating costs are about \$1,500 per year (59).

The cost of an elevated flare system for a 50,000 bbl/day (7,950 m³/day) SRC plant has been roughly estimated from the cost of a flare system for a 350,000 bbl/day (55,650 m³/day) refinery. The 55,650 m³/day refinery flare system incorporates two elevated flares, each costing \$100,000, and one ground flare, costing \$200,000. The waste gas collection system was valued at \$250,000. Total capital cost for the refinery was \$750,000 (59).

Figure 56 presents average load to flare with respect to refinery throughput in bbl/day. From the line drawn through the data, (55,650 m³/day) plant would have a flare loading of 200,000 lb/day (90.9 Mg/day) and a 50,000 bbl/day (7,950 m³/day) plant would have a flare loading of approximately 30,000 lb/day (13.6 Mg/day).

Using six-tenth factor analysis and assuming a similar scaled down version of the 350,000 bbl/day refinery flare system, the cost of a flare system for the 50,000 bbl/day SRC plant has been approximated. Results are listed below in Table 71.

TABLE 71. ESTIMATED COSTS FOR FLARE SYSTEM OF
A 50,000 BBL/DAY SRC PLANT (59)

Unit	Capital Cost	Operating Cost
Elevated Flares (2)	\$64,100	\$3,000/yr
Ground Flare (1)	64,100	1,500/yr
Waste Gas Collection System	80,000	-
Total	\$208,200	\$4,500/yr

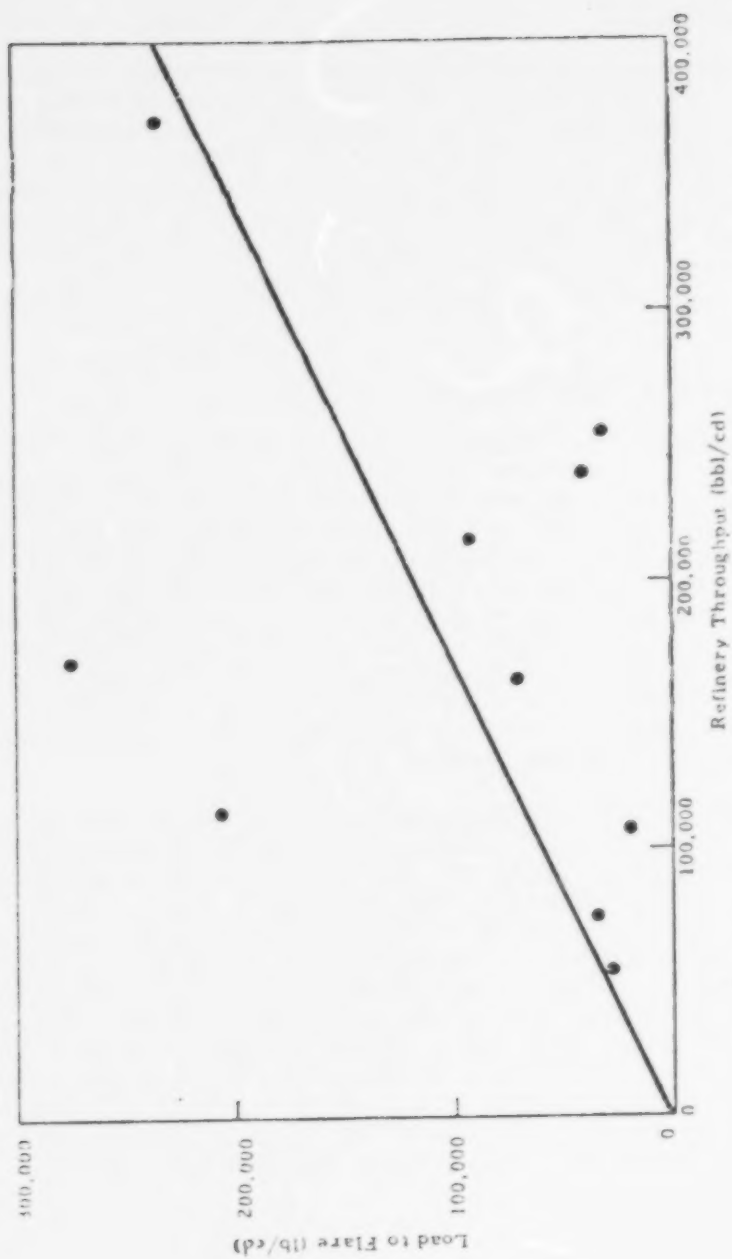


Figure 56. Crude Run vs Flare Loading (59)

7.0 Environmental Emissions and Factors Achieved

7.1 Introduction

In this chapter estimated concentrations of specific pollutants in air, water, and solids waste streams after treatment are compared with Multimedia Environmental Goals (MEG's). Those MEG levels used for comparison are minimum acute toxicity effluent levels based on health effects. It is noted when the constituent level in the treated stream exceeds the MEG. Future studies may be warranted to determine ways to reduce the emissions to acceptable levels. This could consist of either process or control modifications.

7.2 Multimedia Environmental Goals

Multimedia Environmental Goals (MEG's) are levels of contaminants (in ambient air, water, or land) as in emissions or effluents conveyed to ambient media that are judged to be (1) appropriate for preventing certain negative effects on the surrounding populations or ecosystems or (2) representative of the control limits achievable through technology (60). A comparison of MEG's with emission characteristics is an integral part of the environmental assessment methodology being developed by the Fuel Process Branch of IERL/EPA at RTP. This assessment includes a comparison to MEG's of contaminant levels associated with emissions and effluents from a point source.

The MEG's provide sets of control goals for specific chemical contaminants, complex effluents, and nonchemical substances based on some of the criteria options that might be considered in defining "desirable control levels." These sets of goals then can be compared with actual contamination levels for environmental assessment purposes. A master list of more than 600 chemical substances and physical substances is being completed using prescribed selection factors. At this time MEG's which focus on fossil fuel process, particularly coal conversion, have been prepared for 216 of these contaminants. Three levels of priority were assigned to the selection factors to determine which substances should be included in the master list for MEG's.

- Primary Selection Factors - The pollutant is associated with fossil fuel processes.
- Secondary Selection Factors - Substances typical of fossil fuel processes and
 - Federal ambient, emission, or occupational criteria exist or have been proposed
 - A TLV has been established or an LD₅₀ has been reported
 - The substance is a suspected carcinogen
 - The substance appears on the EPA Consent Decree List.
- Tertiary Selection Factors (optional) - Consideration is also given the substances present as a pollutant in the environment and/or identified as being highly toxic.

The current version of a typical MEG chart is shown in Figure 57. The chart has been designed to display, in inter-related tables, Emission Level Goals and Ambient Level Goals for a specific chemical contaminant. Each table is divided into columns devoted to specific criteria for describing desirable control levels [for example, Toxicity Based Ambient Level Goals (Based on health effects)]. Within each column, space is provided for concentration levels to be specified for air, water, and land in units consistent with those indicated in the index column at the left. Only numbers will appear within the MEG's charts. The name of the substance addressed, its category number and appropriate toxicity indicator (based on human health effects associated with the substance as an air contaminant) are all presented in bold letters in the upper right-hand corner of each chart.

7.2.1 Emission Level Goals

Emission Level Goals presented in the top half of the MEG's chart, actually pertain to gaseous emissions to the air, aqueous effluents to water and solid waste to be disposed to land. These Goals may have as their bases technological factors or ambient factors. Technological factors refer to the limitations placed on control levels by technology, either existing or developing (i.e., equipment capabilities or process parameters). The Standards of Performance for New Stationary Sources² provide an example of promulgated Emission Level Goals based on technology.

MULTIMEDIA ENVIRONMENTAL GOALS

18A
PHENOL

EMISSION LEVEL GOALS							
	I. Based on Best Technology		II. Based on Ambient Factors				
	A. Existing Standards	B. Developing Technology	A. Minimum Acute Toxicity Effluent		B. Ambient Level Goal*		C. Elimination of Discharge
	NSPS, BPT, BAT	Engineering Estimates (R&D Goals)	Based on Health Effects	Based on Ecological Effects	Based on Health Effects	Based on Ecological Effects	Natural Background*
Air, $\mu\text{g}/\text{m}^3$ (ppm Vol)			1.9E4 (5)		45 (0.01)		
Water, $\mu\text{g}/\text{l}$ (ppm Wt)			5.0E0	5.0E2	1	100	
Land, $\mu\text{g}/\text{g}$ (ppm Wt)			1.0E-2	1.0E0	0.002	0.2	

*To be multiplied by dilution factor

AMBIENT LEVEL GOALS					
	I. Current or Proposed Ambient Standards or Criteria		II. Toxicity Based Estimated Permissible Concentration		III. Zero Threshold Pollutants Estimated Permissible Concentration
	A. Based on Health Effects	B. Based on Ecological Effects	A. Based on Health Effects	B. Based on Ecological Effects	Based on Health Effects
Air, $\mu\text{g}/\text{m}^3$ (ppm Vol)			45 (0.01)		
Water, $\mu\text{g}/\text{l}$ (ppm Wt)	1+	100+	260	500	
Land, $\mu\text{g}/\text{g}$ (ppm Wt)			0.002	0.2	

+Phenolic compounds.

Figure 57. A Typical MEG Chart

Since there is obviously a relationship between contaminant concentrations in emissions and the presence of these contaminants in ambient media, it is imperative to consider ambient factors when establishing emission level goals. Ambient factors included in the MEG's chart as criteria for Emission Level Goals include:

- (1) Minimum Acute Toxicity Effluents (MATE's)--concentrations of pollutants in undiluted emission streams that would not adversely affect those persons or ecological systems exposed for short periods of time.
- (2) Ambient Level Goals--i.e., estimated permissible concentrations (EPC's) of pollutants in emission streams which, after dispersion, will not cause the level of contamination in the ambient receiving medium to exceed a safe continuous exposure concentration.
- (3) Elimination of Discharge (EOD)--concentrations of pollutants in emission streams which, after dilution, will not cause the level of contamination to exceed levels measured as "natural background."

Although technology based Emission Level Goals are highly source specific, goals based on ambient factors can be considered universally applicable to discharge streams for any industry. The Emission Level Goals based on EPC's for example, correspond to the most stringent Ambient Level Goals (dilution factor to be applied) appearing in the MEG's chart, regardless of source of emission. This format for presentation of Emission Level Goals has evolved during the course of the MEG's project and is significantly different from the initial chart introduced some 18 months ago. Elimination of Discharge, as a criterion for Emission Level Goals, was added about a year ago. In another interim version, columns specifying dilution factors in multiples of ten were included under the Emission Level Goals based on ambient factors. Later, Minimum Acute Toxicity Effluents (MATE's) were incorporated and the dilution factor columns deleted. It is likely that the chart will be further altered as the MEG's become more refined. The format presented here serves well for displaying MEG's at this stage of development.

7.2.2 Ambient Level Goals

The lower half of the MEG's chart is designed to present three classifications of Ambient Level Goals. All of these goals describe estimated permissible concentrations (EPC's) for continuous exposure. The Ambient Level Goals presented in the chart are those based on:

- (1) Current or proposed federal ambient standards of criteria.
- (2) Toxicity (acute and chronic effects considered).
- (3) Carcinogenicity or teratogenicity (for zero threshold pollutants).

The term "zero threshold pollutants" is used to distinguish contaminants demonstrated to be potentially carcinogenic or teratogenic. The concept of thresholds is based on the premise that there exists for every chemical substance, some definable concentration below which that chemical will not produce a toxic response in an exposed subject. The existence of thresholds for carcinogens, teratogens and mutagens has been widely debated and is still unresolved. The term "zero threshold pollutants" is used as a convenience.

For the purposes of this report estimated constituent levels after controls were matched with the Minimum Acute Toxicity Effluent factors. In all cases the lower, or more stringent, MATE was employed for the comparison.

If the level after controls exceeds the MATE value, the potential exists for emission of excessive quantities of specific contaminants. Further study might be warranted to determine alternatives such as control or process modifications to reduce these levels.

7.3 Criteria

Estimates of pollutant levels were derived from a variety of sources. The information used includes results of sampling at the Fort Lewis pilot plant, emission data on similar processes found in other industries, and engineering calculations based on material balances included in this report. It should be noted that all estimates of constituent levels are only indicative of the quantities that might be found in the specific waste streams. Until additional sampling data is available from the pilot plant (or preferably a demonstration or commercial facility) accurate profiles of the emissions cannot be developed.

Tables 72, 73, and 74 show estimated air emissions from three units in the coal preparation module (27). It was assumed that the trace composition of the particulates emitted was identical to that of raw coal (see Table 3) and that total particulate loading was as calculated in the previous chapter. Trace metals were determined for each control option, based on the respective estimated efficiencies. Estimated emissions were found to be at least one order of magnitude lower in most cases. Chromium and was found to exceed the MEG's by factors of 2.0-12.0 using the high efficiency cyclone or wet scrubber. Aluminum also exceeded MEG values by a factor of 1.1-1.6 using these options. No MEG's were exceeded when using the cyclone and baghouse combination. No trace metal MEG's were exceeded by flow dryer emissions.

In addition to trace metal levels in the flow dryer stream, the CO₂ emission level was calculated, based upon material balances prepared for this report, and compared with the corresponding MEG.

<u>Emission Level</u>	<u>MATE, health</u>
$1.9 \times 10^8 \mu\text{g}/\text{m}^3$	$9 \times 10^6 \mu\text{g}/\text{m}^3$

The concentration in the stream exceeds the MEG by two orders of magnitude. However, this should not impose any serious health effects at this time.

An estimate of the Stretford tailgas composition and concentration is matched with MEG's in Table 75. Pollutant levels after both incineration and carbon adsorption are compared. These levels were estimated using the material balance from engineering calculations outlined in Chapter 6. It is apparent that carbon adsorption emissions exceed MEG values for H₂S and NH₃. Incineration only exceeds the MEG for CO₂, and therefore presents a more acceptable alternative.

In Table 76, MEG's and corresponding air emissions from the steam plant are listed (60,61). The polynuclear aromatic hydrocarbon (PNA) data were based on data found in the cited literature. It should be noted that the type of coal combusted was not specified in the literature. The trace metal data were based upon controlled emissions, while the reported PNA levels were based upon uncontrolled emissions. Efficiencies of the various control options were used to calculate final emission levels. Both PNA's and trace metals were assumed to consist entirely of particulate matter in these calculations. It is apparent that chromium and vanadium levels exceed MEG's when using even the most efficient SO_x wet scrubbing techniques. MEG's for chromium are exceeded by factors of 9.2-18 while MEG's for vanadium are exceeded by factors of 4-8.1.

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TABLE 72. A COMPARISON OF ESTIMATED AIR EMISSIONS
FROM COAL RECEIVING AND MEG'S - TRACE METALS

Element	MEG	Cyclone & Baghouse	Exceeds MEG	High Efficiency Cyclone	Exceeds MEG	Wet Scrubber	Exceeds MEG
Tl	6×10^3	2.9×10^1		2.9×10^2		4.3×10^1	
Nb	6×10^3	2.1×10^1		2.1×10^2		3.1×10^2	
B	3.1×10^3	6.0×10^0		5.9×10^1		8.9×10^1	
F		3.0×10^0		3.0×10^1		4.5×10^1	
Zn	4×10^3	1.8×10^1		1.8×10^2		2.7×10^2	
Mn	5×10^3	2.0×10^0		2.0×10^1		3.0×10^1	
Sr	3×10^3	2.0×10^0		2.0×10^1		3.0×10^1	
Ca		2.0×10^0		2.0×10^1		3.0×10^1	
Ba	5×10^2	4.6×10^0		4.6×10^1		6.8×10^1	
As	2×10^0	2.0×10^{-1}		2.0×10^0		3.0×10^0	X
Cu	2×10^2	5.0×10^{-1}		5.0×10^0		7.0×10^0	
V	5×10^2	1.4×10^0		1.4×10^1		2.1×10^1	
Cr	1×10^0	8.0×10^{-1}		8.0×10^0	X	1.2×10^1	X
Al	1.5×10^1	9.0×10^{-1}		9.0×10^0		1.3×10^1	
Se	7×10^2	9.0×10^{-2}		9.0×10^{-1}		1.3×10^0	
Pb	1.5×10^2	1.1×10^0		1.1×10^1		1.6×10^1	
Mo	5×10^3	4.0×10^1		4.0×10^2		6.0×10^0	
Ge	5.6×10^2	2.0×10^{-1}		2.0×10^0		3.0×10^0	
Co	5×10^1	3.0×10^{-1}		3.0×10^0		4.0×10^0	
Rn		2.0×10^{-1}		2.0×10^0		3.0×10^0	
Bi	5×10^2	4.0×10^{-2}		4.0×10^{-1}		6.0×10^{-1}	
Be	2×10^0	6.0×10^{-2}		6.0×10^{-1}		9.0×10^{-1}	
Li	1×10^1	2.0×10^{-1}		2.0×10^0		3.0×10^0	
Re		5.0×10^{-2}		5.0×10^{-1}		7.0×10^{-1}	
Yt		2.0×10^{-2}		2.0×10^{-1}		3.0×10^{-1}	
Hf	4×10^1	1.0×10^{-2}		1.0×10^{-1}		1.0×10^{-1}	
Ag	1×10^1	1.0×10^{-1}		1.0×10^0		1.0×10^{-2}	
Al	5.2×10^3	5.6×10^3		5.6×10^3	X	8.4×10^3	X
Br		6.0×10^{-1}		6.0×10^0		9.0×10^0	
Ga		3.2×10^0		3.2×10^1		4.8×10^1	
Ce		5.0×10^{-1}		5.0×10^0		7.0×10^0	
Ca		5.0×10^{-2}		5.0×10^{-1}		7.0×10^{-1}	
Cl		6.7×10^1		6.7×10^2		1.0×10^3	
De		4.0×10^{-2}		4.0×10^{-1}		6.0×10^{-1}	
Eu		1.0×10^{-2}		1.0×10^{-1}		1.5×10^{-1}	
Ga	5.0×10^3	1.0×10^{-1}		1.0×10^0		1.5×10^0	
Hf		2.0×10^{-2}		2.0×10^{-1}		3.0×10^{-1}	
In		6.0×10^{-3}		6.0×10^{-2}		9.0×10^{-2}	
I		8.0×10^{-2}		8.0×10^{-1}		1.2×10^0	
Fe		7.8×10^{-2}		7.8×10^{-1}		1.2×10^0	
La							
Lu							
P	1.0×10^2	1.8×10^0		1.8×10^1		2.8×10^1	
K	2.0×10^3	7.1×10^1		7.1×10^2		1.1×10^3	
Rb		7.0×10^{-1}		7.0×10^0		1.0×10^1	
Sc	5.3×10^3	1.0×10^{-1}		1.0×10^0		1.5×10^0	
Si		1.1×10^3		1.1×10^4		1.7×10^4	
Sa		2.8×10^1		2.8×10^2		4.2×10^2	
Ta		7.0×10^{-3}		7.0×10^{-2}		1.0×10^{-1}	
Tb		7.0×10^{-3}		7.0×10^{-2}		1.0×10^{-1}	
Tl	1.0×10^0	3.0×10^{-2}		3.0×10^{-1}		4.0×10^{-1}	
Th		2.2×10^0		2.2×10^1		3.3×10^1	
W	1.0×10^3	3.0×10^{-2}		3.0×10^{-1}		4.0×10^{-1}	
U	9.0×10^0	7.0×10^{-2}		7.0×10^{-1}		1.0×10^0	

All values are in $\mu\text{g}/\text{m}^3$.

TABLE 73. A COMPARISON OF ESTIMATED AIR EMISSIONS FROM COAL RECLAIMING AND CRUSHING WITH MEG's - TRACE METALS

Element	MEG	Cyclone & Baghouse	Exceeds MEGS	High Efficiency Cyclone	Exceeds MEG	Wet Scrubber	Exceeds MEG
Tl	6×10^{-3}	7×10^0		7×10^{-1}		1.1×10^{-2}	
Hg	6×10^{-3}	5×10^0		5×10^{-1}		7.5×10^{-1}	
B	3.1×10^{-3}	1.4×10^0		1.4×10^{-1}		2.1×10^{-1}	
F		6×10^{-1}		6×10^0		9×10^0	
Zn	4×10^{-3}	4×10^0		4×10^{-1}		6×10^{-1}	
Mn	5×10^{-3}	5×10^{-1}		5×10^0		7.5×10^0	
Sr	3×10^{-3}	4×10^{-1}		4×10^0		6×10^0	
Zr		5×10^{-1}		5×10^0		7.5×10^0	
Ba	5×10^{-2}	1.1×10^0		1.1×10^{-1}		1.7×10^{-1}	
As	2×10^0	6×10^{-2}		6×10^{-1}		9×10^{-1}	
Cu	2×10^2	1×10^{-1}		1×10^0		1.5×10^0	
V	5×10^2	3×10^{-1}		3×10^0		4.5×10^0	
Cr	1×10^0	2×10^{-1}		2×10^0	X	3×10^0	X
Ni	1.5×10^{-1}	2×10^{-1}		2×10^0		3×10^0	
Se	2×10^2	2×10^{-2}		2×10^{-1}		3×10^{-1}	
Pb	1.5×10^2	3×10^{-1}		3×10^0		4.5×10^0	
Mn	5×10^3	9×10^{-2}		9×10^{-1}		1.4×10^0	
Ge	5.6×10^2	6×10^{-2}		6×10^{-1}		9×10^{-1}	
Co	5×10^{-1}	7×10^{-2}		7×10^{-1}		1×10^0	
Sn		5×10^{-2}		5×10^{-1}		8×10^{-1}	
Sb	5×10^{-2}	1×10^{-2}		1×10^{-1}		2×10^{-1}	
Be	2×10^0	2×10^{-2}		2×10^{-1}		3×10^{-1}	
Gd	1×10^{-1}	4×10^{-2}		4×10^{-1}		6×10^{-1}	
Sm		5×10^{-2}		1×10^{-1}		2×10^{-1}	
Hf	1×10^{-1}	2×10^{-3}		2×10^{-2}		3×10^{-2}	
Ag	1×10^{-1}	3×10^{-4}		3×10^{-3}		5×10^{-3}	
Al	5.2×10^3	1.4×10^2		1.4×10^3		2.1×10^3	
Ir		2×10^{-1}		2×10^0		3×10^0	
Cu		7.9×10^{-1}		8×10^{-1}		1.2×10^3	
Co		1×10^{-1}		1×10^0		1.5×10^0	
Co		1×10^{-2}		1×10^{-1}		2×10^{-1}	
Cl		1.6×10^{-1}		1.6×10^{-2}		2.4×10^{-2}	
Dy		1×10^{-2}		1×10^{-1}		2×10^{-1}	
Eu		3×10^{-3}		3×10^{-2}		5×10^{-2}	
Ga	5×10^{-3}	3×10^{-2}		3×10^{-1}		5×10^{-1}	
Hf		5×10^{-3}		5×10^{-2}		8×10^{-2}	
Io		1×10^{-3}		1×10^{-2}		2×10^{-2}	
I		2×10^{-2}		2×10^{-1}		3×10^{-1}	
Fe		1.9×10^2		1.9×10^{-2}		2.9×10^3	
La		7×10^{-2}		7×10^{-1}		1×10^0	
Li		8×10^{-4}		8×10^{-3}		1×10^{-2}	
P	1×10^{-2}	5×10^{-1}		5×10^0		7.5×10^0	
R	2×10^3	1.7×10^1		1.7×10^{-2}		2.6×10^2	
Rb		2×10^{-1}		2×10^0		3×10^0	
Sc	5.3×10^{-4}	3×10^{-2}		3×10^{-1}		5×10^{-1}	
Si		2×10^2		2.8×10^3		4.1×10^3	
Sa		6.8×10^0		6.8×10^{-1}		1.0×10^2	
Ta		2×10^{-3}		2×10^{-2}		3×10^{-2}	
Tb		2×10^{-3}		2×10^{-2}		3×10^{-2}	
Tl	1×10^{-2}	7×10^{-1}		7×10^{-2}		1×10^{-1}	
Th		7×10^{-2}		7×10^{-1}		3×10^{-1}	
W	1×10^{-3}	7×10^{-3}		7×10^{-2}		1×10^{-1}	
U	9×10^0	2×10^{-2}		2×10^{-1}		3×10^{-1}	

All values are in $\mu\text{g}/\text{m}^3$

TABLE 74. A COMPARISON OF ESTIMATED AIR EMISSIONS
FROM THE FLOW DRYER AND MEG'S - TRACE METALS

Element	MEG	Baghouse	Exceeds MEG	Wet Scrubber	Exceeds MEG
Tl	6×10^3	5×10^{-1}		7.6×10^0	
Mg	6×10^3	4×10^{-1}		6.1×10^0	
S	3.1×10^3	1×10^{-1}		1.5×10^0	
F		5×10^{-2}		8×10^{-1}	
Zn	4×10^3	3×10^{-1}		4.6×10^0	
Mn	5×10^3	4×10^{-2}		6×10^{-1}	
Sr	3×10^3	3×10^{-2}		5×10^{-1}	
Zr		4×10^{-2}		6×10^{-1}	
Ba	5×10^3	8×10^{-2}		1.2×10^0	
As	2×10^0	4×10^{-3}		6×10^{-2}	
Cu	2×10^2	1×10^{-2}		2×10^{-1}	
V	5×10^2	2×10^{-2}		3×10^{-1}	
Cr	1.5×10^1	1×10^{-2}		2×10^{-1}	
Ni	1.5×10^1	2×10^{-2}		3×10^{-1}	
Se	2.0×10^3	2×10^{-3}		3×10^{-2}	
Pb	1.5×10^2	2×10^{-2}		3×10^{-1}	
Mo	3×10^3	7×10^{-3}		1×10^{-1}	
Ga	5.6×10^2	4×10^{-3}		6×10^{-2}	
Co	3×10^1	5×10^{-3}		8×10^{-2}	
Sn		3×10^{-3}		5×10^{-2}	
Sb	5×10^2	7×10^{-4}		1×10^{-2}	
Be	2×10^0	1×10^{-3}		2×10^{-2}	
Cd	1×10^1	3×10^{-3}		5×10^{-2}	
Sc		9×10^{-4}		1×10^{-2}	
Hg	1×10^1	1×10^{-4}		2×10^{-3}	
Ag	1×10^1	2×10^{-5}		3×10^{-4}	
Al	5.2×10^3	1×10^1		1.5×10^2	
Br		1×10^{-2}		2×10^1	
Ca		5.7×10^0		8.7×10^1	
Ce		1×10^{-2}		2×10^{-1}	
Cs		9×10^4		1×10^{-2}	
Cl		1.2×10^0		1.8×10^1	
Dy		7×10^{-4}		1×10^{-2}	
Eu		2×10^{-4}		3×10^{-3}	
Ga	5×10^3	2×10^{-3}		3×10^{-2}	
Hf		4×10^{-4}		6×10^{-3}	
In		1×10^{-4}		2×10^{-3}	
I		1×10^{-3}		2×10^{-2}	
Fe		1.4×10^1		2.1×10^2	
La		5×10^{-3}		8×10^{-2}	
Luz		6×10^{-5}		9×10^{-4}	
P	1×10^2	3×10^{-2}		5×10^{-1}	
K	2×10^3	1.3×10^0		2×10^1	
Rb		1×10^{-2}		2×10^{-1}	
Sc	5.3×10^4	2×10^{-3}		3×10^{-2}	
Si		2×10^1		3.1×10^2	
Na		5×10^{-1}		7.6×10^0	
Ta		1×10^{-4}		2×10^{-3}	
Tb		1×10^{-4}		2×10^{-3}	
Ti	1×10^2	5×10^{-4}		3×10^{-3}	
Th		2×10^{-3}		3×10^{-2}	
U	1×10^3	5×10^{-4}		5×10^{-3}	
Y	8×10^3	1×10^{-3}		7×10^{-2}	

All values are in $\mu\text{g}/\text{m}^3$.

TABLE 75. A COMPARISON OF ESTIMATED STRETFORD TAIL GAS EMISSIONS AND MEG'S

	MEG	Incineration	Exceeds MEG	Carbon Adsorption	Exceeds MEG
H ₂ S	1.5 x 10 ²	7.1		3.8 x 10 ²	X
SO ₂		1.3 x 10 ³		0	
HC		2.7 x 10 ³		9.8 x 10 ³	
NO		3.3 x 10 ³		2.2 x 10 ¹	
CO	4 x 10 ⁴	8.3 x 10 ¹		4.2 x 10 ³	
CO ₂	9 x 10 ⁶	2.2 x 10 ⁷	X	2.2 x 10 ⁷	X
NH ₃	3.5 x 10 ²	3.9 x 10 ¹		2.2 x 10 ³	X

All values are in $\mu\text{g}/\text{m}^3$.

TABLE 76. A COMPARISON OF ESTIMATED AIR EMISSIONS
FROM STEAM GENERATION AND MEG'S (61)

Trace Metals	MEG	Lime Slurry or Soda Limestone or Limestone Scrubbing	Exceeds MEG	MgO Scrubbing	Exceeds MEG
Sb	5×10^2	5.6×10^{-1}		2.8×10^{-1}	
As	2×10^0	7.8×10^{-2}		3.9×10^{-2}	
Be		3.4×10^{-1}		1.7×10^{-1}	
Cd	1×10^1	1.1×10^1		5.7×10^0	
Cr	1×10^0	1.8×10^1	X	9.2×10^0	X
Cu	2×10^2	1.2×10^0		5.9×10^{-1}	
Fe		1.6×10^3		8.4×10^2	
Pb	1.5×10^2	4.2×10^1		2.1×10^1	
Hg	1.0×10^1	2.0×10^0		9.8×10^{-1}	
Ni	1.5×10^1	4.0×10^1		2.0×10^1	
V	1×10^0	8.1×10^0	X	4.0×10^0	X
Zn	4×10^3	8.5×10^1		4.2×10^1	
<u>Organic Compounds</u>					
benzo(a)pyrene	2×10^{-2}	5.4×10^{-3}		2.7×10^{-4}	
pyrene	2.3×10^6	4.3×10^{-3}		2.1×10^{-3}	
fluoranthene	9×10^4	5.2×10^{-3}		2.6×10^{-3}	
benzo(a)- anthracene	4.5×10^1	5.4×10^{-4}		2.7×10^{-4}	

All values in $\mu\text{g}/\text{m}^3$.

The SO₂ levels, calculated from the material balance and efficiencies of scrubbers, are below. No MEG is currently available for SO₂.

<u>Lime Slurry</u>	<u>MgO</u>	<u>Limestone Scrubbing</u>	<u>Potassium Sulfite - Bisulfite</u>	<u>Activated Charcoal</u>
0.7 $\mu\text{g}/\text{m}^3$	0.7 $\mu\text{g}/\text{m}^3$	1.8 $\mu\text{g}/\text{m}^3$	0.7 $\mu\text{g}/\text{m}^3$	1.4 $\mu\text{g}/\text{m}^3$

The estimated trace metal composition of the slag generated during the gasification of the mineral residue is compared with MEG's in Table 77 (60). Information on the residue makeup was available for the Fort Lewis pilot plant (62). It should be realized that instead of Illinois #6 coal, Kentucky coal was used during the sampling. This would affect the actual composition of the stream, but the data available does provide some indication of the makeup of the stream. The estimates present maximum concentrations in the slag assuming no leaching of metals into the clarified quench water purge stream. Actual concentrations are expected to be at most an order of magnitude lower. Mercury and bromine are expected to be volatilized and carried with the product gas, hence they are not expected to appear in any significant concentrations. Even when given an order of magnitude leeway, MEG's for all available metals except scandium and strontium are exceeded.

Table 78 shows wastewater constituent levels (60,62). Influent data on organics is also from a sampling program at Fort Lewis. Compared to the hypothetical plant herein, the Fort Lewis facility does not generate hydrogen, produce process steam, or always use similar control or process technologies. For purposes of calculation, removal efficiency for PNA's was assumed to be 50 percent. Trace metal analyses from another sampling program at the pilot plant were collected for the effluent from the wastewater treatment plant and are listed in Table 79 (60,63). Unlike in Table 77, less than half the MEG's are exceeded.

Table 80 presents MEG's and rough estimates for concentrations of other compounds found in the wastewater as calculated from material balances presented in this report. Insufficient information prevented an accurate determination of concentrations. Hence, comparisons to MEG's could not be accomplished.

TABLE 77. A COMPARISON OF SLAG FROM THE
GASIFIER AND MEG'S - TRACE METALS (62)

Element	Residue & Coal Before Gasification	Slag After Gasification (Max. Conc.)	MEG	Exceeds MEG
Na	1.7×10^6	5.1×10^6		
Fe(%)	7.8×10^0	2.3×10^1		
Cr	8.4×10^1	2.5×10^2	5×10^{-1}	X
Co	1.9×10^1	5.7×10^1	1.5×10^{-1}	X
Ni	7.1×10^1	2.1×10^2	2.0×10^{-2}	X
Sc	8.7×10^0	2.6×10^1	1.6×10^3	
Ba	1.4×10^2	4.2×10^2	5×10^0	X
Sr	1.8×10^2	5.4×10^2	9.2×10^1	X
La	2.8×10^1	8.4×10^1		
Ce	5.6×10^1	1.7×10^2		
Nd	2.7×10^1	8.1×10^1		
Sm	5.3×10^0	1.6×10^1		
Eu	1.1×10^0	3.3×10^0		
Tb	6.6×10^{-1}	2.0×10^0		
Yb	2.1×10^0	6.3×10^0		
Lu	3.1×10^{-1}	9.3×10^{-1}		
Hf	1.4×10^0	4.2×10^0		
Ta	3.8×10^{-1}	1.1×10^0		
Th	6.0×10^0	1.8×10^1		
Rb	6.6×10^0	2.0×10^1		
Cs	3.4×10^0	1.0×10^1		
As	4.4×10^1	1.3×10^2	1×10^{-1}	X
Sb	4.4×10^0	1.3×10^1	4×10^{-1}	X
Zn	7.3×10^1	2.2×10^1	2×10^{-1}	X
*Br	4.3×10^0			
Se	1.2×10^1	3.6×10^1	5×10^{-2}	X
*Hg	8.3×10^{-2}		2×10^{-2}	

All concentrations are in $\mu\text{g/g}$

*Not expected to be present in significant quantities due to volatilization.

TABLE 78. A COMPARISON OF ESTIMATED EFFLUENTS FROM THE WASTEWATER TREATMENT PLANT AND MEGS - ORGANIC COMPOUNDS (60, 62)

	Before Treatment	After Treatment	MEG	Exceeds MEG	Before Treatment	After Treatment	MEG	Exceeds MEG
Indane								
methylindene	1.5×10^4	7.5×10^3			9-methylfluorene	3×10^2	1.5×10^2	
tetralin	$<1 \times 10^2$	$<5 \times 10^1$	1×10^3		1-methylfluorene	2×10^2	1×10^2	
dimethyltetralin	5×10^2	2.5×10^2			anthracene/phenanthrene	1.1×10^3	5.5×10^2	$8.4 \times 10^3 / 2.39 \times 10^6$
naphthalene	5×10^3	2.5×10^3			methyl phenanthrene	3×10^2	1.5×10^2	
2-methylnaphthalene	2×10^3	1×10^3	1×10^4		1-methyl phenanthrene	2×10^2	1×10^2	
dimethylnaphthalene	3×10^2	1.5×10^3			C ₂ -anthracene	$<5 \times 10^1$	$<2.5 \times 10^1$	
dimethylnaphthalene	2×10^3	1×10^3			fluoranthene	4×10^2	2×10^2	1.4×10^6
dimethylnaphthalene	7×10^2	3.5×10^2			dihydropyrene	$<5 \times 10^1$	$<2.5 \times 10^1$	
2-isopropylnaphthalene	2×10^3	1×10^3			pyrene	6×10^2	3×10^2	3.45×10^6
1-isopropylnaphthalene	2×10^2	$<1 \times 10^2$	1.5×10^4		n-octane	2.3×10^3		
biphenyl	5×10^2	2.5×10^2			n-undecane	3×10^2		
acenaphthylene	2×10^2	1×10^1			n-dodecane	3×10^2		
dimethylobiphenyl	$<1 \times 10^2$	$<5 \times 10^1$			n-tridecane	4×10^2		
dimethylobiphenyl	5×10^2	2.5×10^2			n-tetradecane	3×10^2		
dibenzofuran	2×10^2	1×10^2			n-pentadecane	2×10^2		
xanthrene	6×10^2	3×10^2			n-hexadecane	2×10^2		
dibenzothiophene	2×10^2	5×10^1			n-heptadecane	2×10^1		
methylbenzothiophene	1.5×10^3	7.5×10^2			n-octadecane	2×10^1		
dimethylbenzothiophene	$<1 \times 10^2$	$<5 \times 10^1$						
thioxanthene	$<5 \times 10^1$	$<2.5 \times 10^1$						
fluorene	1×10^2	$<5 \times 10^1$						
	3×10^2	1.5×10^2						

All values in $\mu\text{g/l}$.

TABLE 79. A COMPARISON OF ESTIMATED EFFLUENT
CONSTITUENTS FROM THE WASTEWATER TREATMENT
PLANT AND MEG'S - TRACE METALS (60,63)

Component	Emission Level	MEG	Exceeds MEG's
As	$<1 \times 10^0$	5×10^1	
Sb	2×10^0	2×10^2	
Se	1.2×10^0	2.5×10^1	
Mg	3.2×10^3	1×10^1	X
Bi	3.2×10^4		
Ni	1.3×10^1	1×10^1	X
Co	4.1×10^{-1}	2.5×10^2	
Cr	1.5×10^2	2.5×10^2	
Fe	1.25×10^3		
Na	8.3×10^3		
Rb	5.2×10^2		
Cs	2×10^{-2}		
K	1.26×10^3	3×10^4	
Sc	1×10^{-2}	8×10^0	
Tb	1×10^{-2}		
Eu	1×10^{-2}		
Sm	$<6 \times 10^{-2}$		
Cl	$<2 \times 10^{-2}$		
La	5×10^{-1}		
Sr	$<4 \times 10^1$	4.6×10^4	
Ba	$<4 \times 10^1$	2.5×10^0	X
Th	$<1 \times 10^{-2}$		
Hf	$<1 \times 10^{-2}$		
Ta	$<1 \times 10^{-2}$		
Ga	$<4 \times 10^{-2}$	7.4×10^4	
Zn	$<4 \times 10^{-2}$		
Cu	$<1 \times 10^1$		

All concentrations are in $\mu\text{g/l}$.

TABLE 80. A COMPARISON OF OTHER ESTIMATED EMISSIONS
FROM THE WASTEWATER TREATMENT
PLANT AND MEG'S (60)

Component	Emission Levels	MEG	Exceeds MEG
NH ₃	Trace	5×10^{-5}	Not determinable
H ₂ S	Trace	1×10^{-5}	Not determinable
Phenol	$\leq 2.6 \times 10^{-5}$	5×10^{-6}	Not determinable

All values are in $\mu\text{g/l}$.

8.0 Emission Variations for the SRC I System

In the SRC I system, the main product is a low sulfur and ash solid rather than a liquid product. The production of a solid product requires certain basic changes in the SRC system, which are listed below:

- Hydrogenation in the SRC-I mode of operation requires less hydrogen. The hydrogen:coal slurry ratio is 50 to 67 percent lower than the SRC-II ratio (64).
- Vacuum flashing is not incorporated as the main process in the solids separation module. A separation technique producing a higher ash residue will most probably be used. Feasible solids separation processes include rotary pre-coat filtration, solvent de-ashing, and centrifugal techniques.
- The fractionation module produces a wash solvent for filtration, process solvent for slurry preparation, and only a small amount of by-product light oil relative to by-product oils from SRC-II processing (6.7% of the total coal feed as compared to 17.1% for SRC-II) (64).
- Process solvent rather than slurry will be recycled to the coal preparation module. The solvent stream will be recycled from the fractionation module rather than from the phase (gas) separation module.
- Wash solvent is recycled to the solids separation module (only when precoat filtration is used) from fractionation.
- Since the by-product light oil quantity is less, the capacity of the hydrotreating module will be lower than that of an equivalent SRC-II facility (64).
- The solidification module will have a much greater capacity since it will handle the main product stream rather than a residue stream.

- The gas purification module will be slightly smaller because less acid gas will be produced. This is also true for the cryogenic separation module and sulfur recovery.
- Less hydrogen is needed; therefore, the capacity of the hydrogen production module will be lower.

These modifications in the basic system will result in different emissions in SRC-I relative to those of SRC-II. Since the solidification module will undergo a more than two-fold capacity increase, the dust stream flowrates emanating from this module can be expected to be more than twice as large (64). This stream has a high dust loading and is expected to be a major control problem in the SRC-I system.

The use of lower hydrogen:slurry feed ratios will cause less of the coal polymer to be broken down. Less hydrogen sulfide, mercaptans, light hydrocarbons, and ammonia will be produced. Less carbon dioxide and carbon monoxide have also been observed when lower hydrogen:slurry feed ratios are used.

The utilization of lower hydrogen:slurry ratios means that hydrogen production operations do not have to be as large. Therefore, less waste material will be generated in the hydrogen production module. Lower quantities of acid gas, CO₂, flue gas, and wastewater will be produced. Any changes in slag production are difficult to predict, because the change in modular capacity must be balanced against changes in concentration of mineral matter in the gasifier feed mixture, which depends on residue characteristics and mix ratio.

The solids residue stream from solids separation will be reduced by about seven percent (64). It is expected to contain a greater percentage of mineral matter and undissolved coal particles. It may be suitable as a component of the feed to the gasifier; however, it may have to be mixed with a slightly larger quantity of coal to control slagging. There is uncertainty with respect to whether there will be an increase or decrease in slag production from gasification of the SRC-I residue, because of the lack of information on the concentration of mineral matter in the residue, and the uncertainty with respect to how much residue can be used. Also, because of these uncertainties it is difficult to predict the relative amount of residue that must be land-filled.

Since the hydrotreating, gas purification, and cryogenic separation modules will be slightly smaller, quantities of waste streams from these modules are expected to be slightly lower. Also, waste quantities from sulfur recovery, steam generation, and oxygen generation will be decreased because of the decrease in the capacity of hydrogen generation.

Storage and transportation of solid SRC presents a significant and expensive dust control problem while liquid SRC storage facilities would have to be accommodated with vapor recovery systems. Transportation of liquid SRC does not seem to have the control problems that occur when transporting a solid product.

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12.0 Glossary

Auxiliary Process: Processes associated with a technology which are used for purposes that are in some way incidental to the main functions involved in transformation of raw materials into end products. Auxiliary processes are used for recovery of by-products from waste streams, to furnish necessary utilities, and to furnish feed materials such as oxygen which may or may not be required depending on the form of the end product which is desired; e.g., the auxiliary processes for low-and medium-Btu gasification technology include: (1) oxygen plant which is used only for medium-Btu gas; (2) the Stretford plant used to recover sulfur compounds from gaseous waste streams, etc.

By-Product Streams: Discharge streams from which useful materials are recovered to: (1) eliminate undesirable environmental discharges; or (2) recover valuable materials which are most economically isolated from process input stream after it has been physically or chemically transformed; e.g., sulfur is recovered as a by-product from coal gasification to prevent pollution while vanadium is recovered from the ash generated by the burning of residual oil to produce electricity because it is profitable to do so.

Closed Process: For the purposes of this report, a closed process signifies a process which has no waste streams.

Coefficient of Runoff: An empirical constant developed for the purpose of predicting the amount of stormwater runoff as a function of average rainfall intensity and drainage areas. The mathematical relationship is as follows:

$$Q = CIA$$

where: Q = maximum rate of runoff, cubic feet per second (cubic meters per second).

C = coefficient of runoff based on type and character of surface

I = average rainfall intensity, inches per hour (centimeters per hour)

A = drainage area, acres (square meters).

Control Equipment: Equipment whose primary function is to reduce the offensiveness of waste streams discharged to the environment. It is not essential to the economic viability of the process, e.g. if the recovery of sulfur from gas cleaning operations associated with coal gasification involves the use of a Stretford plant. The Stretford process is an auxiliary process and is not control equipment. An incinerator used to clean the tail gas from the Stretford unit would be considered control equipment.

Discharge: The release of pollutants to the environment in the most general sense. Usually applied to intermittent or accidental releases.

Effluent: A discharge of pollutant into the environment. Usually applied to continuous wastewater streams.

Emission: A discharge of pollutants into the environment. Usually applied to continuous atmospheric waste streams, but can be applied to water and solid waste streams also.

Energy Technology: A technology is made of systems which are applicable to the production of fuel or electricity from fossil fuels, radioactive materials, or natural energy sources (geothermal or solar). A technology may be applicable to extraction of fuel, for example, underground gasification; or processing of fuel, for example, coal liquefaction, light water reactor, conventional boilers with flue gas desulfurization.

Final Disposal Process: Processes whose function is to ultimately dispose of solid or liquid waste containing materials which have potential for environmental contamination. The waste materials treated emanate from the collection of process waste streams for final disposal or from treatment of waste streams using control equipment to collect and concentrate the potential pollutants which are subsequently sent to final disposal. Examples of final disposal processes are landfills, lined ponds, etc.

Flottazur: Dissolved air flotation unit.

Fugitive Emissions: Those emissions of air pollutants not directed through ducts or stacks and not amenable to measurement by established source sampling methods.

Input Streams: Materials which are supplied to a process in performance of its intended function. Input materials will consist of primary raw materials, secondary raw materials, or intermediate products.

Intermediate Products: Process output streams that feed from one process to another within a technology for further processing with another technology; for example, for the low- and medium-Btu gasification technology, gasification converts pretreated coal into raw gas which is an intermediate product input to gas cleaning. Where an intermediate product is further processed using a different technology it becomes a secondary raw material which is described below.

LD50 (Lethal dose, 50%): That quantity of a substance administered either orally or by skin contact necessary to kill 50% of exposed animals in laboratory tests within a specified time.

Opacity Rating: A measurement of the opacity of emissions, defined as the apparent obscuration of smoke of a given rating on the Ringelmann chart.

Operation: A specific function, associated with a technology in which a set of processes are employed to produce similar products starting from the same input material; e.g., some operations associated with the technology for coal liquefaction are: (1) coal preparation where the processes employed are receiving, crushing and sizing, drying, and slurry mixing. These processes will be used in different combinations dictated by the type of coal processed; (2) hydrogenation which can be accomplished using any of six hydrogenation processes; and (3) gas purification, where different processes are employed for pressurized vs. atmospheric systems, cleanup of gases containing tar vs. cleanup of tar-free gas, etc.

Output Streams: Discharges from a process which are either end products, intermediate products, by-product streams, or waste streams.

Plant: An existing system which has been defined with the specificity necessary to make it workable under conditions presented at a particular site. Any plant or system may use different combinations of processes as illustrated above. However, all will be comprised of some combination of processes. The combination of plants and systems make up the technology.

Primary Raw Materials: Materials which are extracted (coal, ores, etc.) or grown and harvested (trees, corn, etc.) and processed to yield intermediate or end products. For energy technologies the principal raw materials are fossil fuels, ores for nuclear fuels, geothermal deposits, sunlight.

Process: Processes are basic units which make up an operation. A process is employed to produce chemical or physical transformations of input materials into end products, intermediate products, or by-products. Every process has a definable set of waste streams which are, for practical purposes, unique. The term used without modifiers is used to describe generic processes. Where the term is modified, such as, for example, in the term "Lurgi process", reference is made to a specific process which falls in some generic class consisting of a set of similar processes; for example, the low-and medium-Btu gas technology includes the fixed-bed, atmospheric, dry ash gasifier as one of the gasification processes. Specific processes which are included in this generic class are Wellman-Galusha, Woodhall-Duckham/Gas Integrals, Chapman (Wilputte), Riley-Morgan, and Foster-Wheeler Stoic.

Process Module: A representation of a process which is used to display input and output stream characteristics. When used with other necessary process modules, they can be used to describe a technology, a system or a plant.

Residuals: Uncollected discharges from control equipment used to treat waste streams or discharges from final disposal processes which are used for ultimate disposal of waste material; for example, traces of pollutant that pass through a scrubber cleaning the tail gas from the Claus plant used in coal gasification are residuals. If a scrubber is used to clean the Claus unit tail gas and a bleed stream is sent to a lined pond serving as a final disposal process, any runoff to the environment would be a residual.

Ringelmann Chart: A chart used in air pollution evaluation for assigning an arbitrary number, referred to as the smoke density, to smoke emanating from any source.

Secondary Raw Materials: Materials which are output from one technology and input for another. For the technology with which it is produced, it is an intermediate product. For the technology associated with further processing, it is a secondary raw material; for example, liquid fuel from coal is an intermediate product from coal liquefaction and, if it is burned utilizing a technology associated with production of electricity, it is a secondary raw material.

Six-tenths Factor: A logarithmic relationship between equipment size and cost, used to adjust one set of estimates to a different design size. The simple form of the six-tenths factor is

$$C_n = r^{0.6}C$$

where C_n is the new cost, C is the previous cost, and r is the ratio of new to previous capacity.

System: A set of operations which are representative of a unique combination which is likely to be employed to accomplish a specific objective of a technology; e.g., for coal liquefaction technology, over twenty systems make up the technology. Examples include SRC, H-Coal, and Exxon Donor Solvent Systems.

Threshold Limit Value (TLV): A set of standards established by the American Conference of Governmental Industrial Hygienists for concentrations of airborne substances in workroom air. They are time-weighted averages based on conditions which it is believed that workers may be repeatedly exposed to day after day without adverse effects. The TLV values are intended to serve as guides in control of health hazards, rather than definitive marks between safe and dangerous concentrations.

Waste Streams: Nonproduct output streams from which no by-products are recovered. Waste streams may contain potential pollutants for the air, water or land. The consumption of products results in generation of waste streams. Both processes and auxiliary processes produce waste streams which go directly to a final disposal process or are cleaned with control equipment which collects pollutants which are sent to a final disposal process.

APPENDICES

- A. METRIC CONVERSION FACTORS
- B. FEDERAL AND STATE REGULATIONS

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APPENDIX A. METRIC CONVERSION FACTORS

<u>To Convert From</u>	<u>To</u>	<u>Multiply By</u>
	<u>Acceleration</u>	
ft/s ²	metre per second ² (m/s ²)	3.048-000 E-01
	<u>Area</u>	
Acre (U.S. survey) ¹²	metre ² (m ²)	4.046 873 E+03
ft ²	metre ² (m ²)	9.290 304 E-02
in ²	metre ² (m ²)	6.451 600 E-04
yd ²	metre ² (m ²)	8.361 274 E-01
	<u>Energy (Includes Work)</u>	
British thermal unit (mean)	joule (J)	1.055 87 E+03
Calorie (kilogram, mean)	joule (J)	4.190 02 E+03
kilocalorie (mean)	joule (J)	4.190 02 E+03
	<u>Length</u>	
foot	metre (m)	3.048 000 E-01
inch	metre (m)	2.540 000 E-02
yard	metre (m)	9.144 000 E-01
	<u>Mass</u>	
grain	kilogram (kg)	6.479 891 E-05
grain	kilogram (kg)	1.000 000 E-03
pound (lb avoirdupois)	kilogram (kg)	4.535 924 E-01
ton (metric)	kilogram (kg)	1.000 000 E+03
ton (short, 2000 lb)	kilogram (kg)	9.071 847 E+02
	<u>Mass Per Unit Area</u>	
lb/ft ²	kilogram per metre ² (kg/m ²)	4.882 428 E+00

APPENDIX A. METRIC CONVERSION FACTORS (Continued)

<u>To Convert From</u>	<u>To</u>	<u>Multiply By</u>
<u>Mass Per Unit Length</u>		
lb/ft	kilogram per metre (kg/m)	1.488 164 E+00
lb/in	kilogram per metre (kg/m)	1.785 797 E+01

Mass Per Unit Time (Includes Flow)

lb/h	kilogram per second (kg/s)	1.259 979 E-04
lb/min	kilogram per second (kg/s)	7.559 873 E-03
ton (short)/h	kilogram per second (kg/s)	2.519 958 E-01

Mass Per Unit Volume (Includes Density & Mass Capacity)

lb/ft ³	kilogram per metre ³ (kg/m ³)	1.601 846 E+01
lb/gal (U.S. liquid)	kilogram per metre ³ (kg/m ³)	1.198 264 E+02
lb/yd ³	kilogram per metre ³ (kg/m ³)	5.932 764 E-01

Power

Btu (thermochemical)/h	watt (W)	2.930 711 E-01
Btu (thermochemical)/h	watt (W)	2.928 751 E-01
cal (thermochemical)/min	watt (W)	6.973 333 E-02
cal (thermochemical)/s	watt (W)	4.184 000 E+00

Pressure or Stress (Force Per Unit Area)

atmosphere (standard)	pascal (Pa)	1.013 250 E+05
foot of water (39.2°F)	pascal (Pa)	2.988 98 E+03
lbf/ft ²	pascal (Pa)	4.788 026 E+01
lbf/in ² (psi)	pascal (Pa)	6.894 757 E+03

Temperature

degree Celsius	Kelvin (K)	$t_K = t_{°C} + 273.15$
degree Fahrenheit	degree Celsius	$t_{°C} = (t_{°F} - 32) / 1.8$
degree Fahrenheit	Kelvin (K)	$t_K = (t_{°F} + 459.67) / 1.8$
degree Rankine	Kelvin (K)	$t_K = t_{°R} / 1.8$
Kelvin	degree Celsius	$t_{°C} = t_K - 273.15$

APPENDIX A. METRIC CONVERSION FACTORS (Continued)

<u>To Convert From</u>	<u>To</u>	<u>Multiply By</u>
<u>Velocity (Includes Speed)</u>		
ft/h	metre per second (m/s)	3.466 667 E-05
ft/min	metre per second (m/s)	5.080 000 E-03
ft/s	metre per second (m/s)	3.048 000 E-01
in/s	metre per second (m/s)	2.540 000 E-02
<u>Viscosity</u>		
centipoise	pascal second (Pa·s)	1.000 000 E-03
centistokes	metre ² per second (m ² /s)	1.000 000 E-06
poise	pascal second (Pa·s)	1.000 000 E-01
stokes	metre ² per second (m ² /s)	1.000 000 E-04
<u>Volume (Includes Capacity)</u>		
acre-foot (U.S. survey)	metre ³ (m ³)	1.233 489 E+03
barrel (oil, 42 gal)	metre ³ (m ³)	1.589 873 E-01
ft ³	metre ³ (m ³)	2.831 685 E-02
gallon (U.S. liquid)	metre ³ (m ³)	3.785 412 E-03
litre*	metre ³ (m ³)	1.000 000 E-03
<u>Volume Per Unit Time (Includes Flow)</u>		
ft ³ /min	metre ³ per second (m ³ /s)	4.719 474 E-04
ft ³ /s	metre ³ per second (m ³ /s)	2.831 685 E-02
gal (U.S. liquid/day)	metre ³ per second (m ³ /s)	4.381 264 E-08
gal (U.S. liquid/min)	metre ³ per second (m ³ /s)	6.309 020 E-05

*In 1964 the General Conference on Weights and Measures adopted the name litre as a special name for the cubic decimetre. Prior to this decision the litre differed slightly (previous value, 1.000028 dm³) and in expression of precision volume measurement this fact must be kept in mind.

APPENDIX B. FEDERAL AND STATE REGULATIONS

The following consists of two sections: (1) Federal regulations, and (2) Selected state regulations. Federal regulations have been discussed in Chapter 4 of this report. Emission standards and effluent guidelines for air and water pollutants and solid wastes are given in Tables 81 through 84.

Section 2 presents environmental policies of 16 states, other than Illinois, abundant in coal reserves and therefore possessing potential for commercial siting of an SRC plant. Emphasis is placed on standards and guidelines which are more stringent than their federal counterparts or are involved with areas for which no federal legislation exists. Regulations applying to environmentally sensitive areas with state boundaries are also included.

Key to symbols and abbreviations applicable to all tables of the Appendix.

max	Denotes maximum
AAM	Denotes Annual Arithmetic Mean
AGM	Denotes Annual Geometric Mean
*	Denotes that the maximum values is not to be exceeded more than once per year.
JTU	Denotes Jackson Turbidity Units
COH/1000 LM	Denotes Coefficient of Haze per 1000 linear meters
COH/1000 LF	Denotes Coefficient of Haze per 1000 linear feet

1. FEDERAL REGULATIONS

TABLE 81. NATIONAL PRIMARY AND SECONDARY AMBIENT
AIR QUALITY STANDARDS (65)

Constituent	Concentration		Remarks
	Metric	English	
Sulfur Oxides			
primary	80 ug/m ³	9.4×10^{-4} grain/yd ³	A.A.M.
	365 ug/m ³	4.3×10^{-3} grain/yd ³	24 hr max*
secondary	1300 ug/m ³	1.5×10^{-2} grain/yd ³	3 hr max*
Particulates			
primary	75 ug/m ³	8.8×10^{-4} grain/yd ³	A.G.M.
	260 ug/m ³	3.1×10^{-3} grain/yd ³	24 hr max*
secondary	60 ug/m ³	7.1×10^{-4} grain/yd ³	A.G.M.
	150 ug/m ³	1.8×10^{-3} grain/yd ³	24 hr max*
Carbon Monoxide			
primary and secondary	10 ug/m ³	0.12 grain/yd ³	8 hr max*
	40 ug/m ³	0.79 grain/yd ³	1 hr max*
Photochemical Oxidants			
primary and secondary	160 ug/m ³	1.9×10^{-3} grain/yd ³	1 hr max*
Hydrocarbons			
primary and secondary	160 ug/m ³	1.9×10^{-3} grain/yd ³	3 hr max* (6-9 A.M.)
Nitrogen Dioxide			
primary and secondary	100 ug/m ³	1.2×10^{-3} grain/yd ³	A.A.M.

Reference Conditions: Temperature = 25°C = 77°F

Pressure = 760 mm Hg = 29.92 in Hg = 1 atmosphere

TABLE 82. FEDERAL NEW SOURCE PERFORMANCE
STANDARDS OF RELATED TECHNOLOGIES (65)

Coal Preparation - Particulates			
Type of Equipment	Metric	Standard English	Opacity
Thermal Dryers	0.057 mg/m ³	2.2x10 ⁻⁴ grain/yd ³	20%
Coal Cleaning	0.033 mg/m ³	1.3x10 ⁻⁴ grain/yd ³	10%
Processing, Conveying and Storage	-----	-----	20%
Fossil Fuel Steam Generators			
Constituent	Metric	Standard English	Opacity
Particulates	0.17 kg/10 ⁶ kcal	0.10 lb/10 ⁶ Btu	20% (1)
Sulfur Dioxide (solid fuels)	2.07 kg/10 ⁶ kcal	1.21 lb/10 ⁶ Btu	----
Nitrogen Oxides (solid fuels)	1.21 kg/10 ⁶ kcal	0.70 lb/10 ⁶ Btu	----
Petroleum Liquid Storage Vessels			
Constituent	Vapor Pressure		Requirement
	Metric	English	
Hydrocarbons	78-570 mm Hg	3.0-22.4 in Hg	(2)
	570 mm Hg	22.4 in Hg	(3)

(1) 40% opacity allowed 2 minutes/hr

(2) floating roof or vapor recovery system or equivalent

(3) vapor recovery system or equivalent

TABLE 83. FEDERAL EFFLUENT GUIDELINES AND
STANDARDS FOR NEW SOURCES (65)

Coal Preparation

Constituent	Concentration			
	1 day maximum		30 day average	
	mg/l	grain/gallon	mg/l	grain/gallon
Total Iron	7.0	0.41	3.5	0.20
Total Manganese	4.0	0.23	2.0	0.12
Total Suspended Solids	20.0	1.17	35.0	2.04
pH range: 6.0-9.0				

By-Product Coking

Constituent	Concentration			
	1 day maximum		30 day average	
	kg/kg	lb/ton	kg/kg	lb/ton
Cyanide A	3×10^{-4}	7.26×10^{-4}	1×10^{-4}	2.42×10^{-4}
Phenol	6×10^{-4}	1.45×10^{-3}	2×10^{-4}	4.84×10^{-4}
Ammonia	1.26×10^{-2}	3.05×10^{-2}	4.2×10^{-3}	1.02×10^{-3}
Sulfide	3×10^{-4}	7.26×10^{-4}	1×10^{-4}	2.42×10^{-4}
Total Suspended Solids	3.12×10^{-2}	7.55×10^{-2}	1.04×10^{-2}	2.52×10^{-4}
pH range: 6.0-9.0				

TABLE 84. SOME EPA REQUIREMENTS AND
RECOMMENDATIONS FOR SOLID WASTES (64)

Aspect of Disposal	Requirement	Recommendations
Design	approval by professional engineer and responsible agency	analysis of solid waste materials; maintenance program; projection of subsequent use
Water Quality	compliance with Federal Water Pollution Control Act	projections of solid waste-soil-groundwater relationship
Air Quality	compliance with clean air act, state and local laws	dust control program
Gas Control	on-site control of decomposition gases	preventing gas from concentrating to prevent explosions and toxicity hazards
Cover Material	cover shall be applied as necessary to minimize fire, odors, dust, etc.	minimum of 2 ft. final cover
Compaction	compaction to the smallest practicable volume	maximum depth of solid waste layers (2 ft)

2. SELECTED STATE POLICIES

ALASKA (53)

Ambient air quality standards and standards for industrial process emissions have been established. Table 85 shows the standards and reference conditions. Emissions standards for industrial processes are described in Table 86.

Water quality parameters are dependent on water uses, which range from potable water to industrial water. Table 87 defines the standards required for various parameters such as pH, dissolved organics, etc. for these water use classifications.

Regulations for the management of solid waste are directed primarily toward municipal wastes rather than industrial. Should leaching or permafrost prove a problem, special disposal procedures must be submitted to the Department of Environmental Conservation. A minimum of two feet of earth must be maintained between solid wastes and the anticipated high ground water table. Surface drainage must be prevented from coming into contact with the landfill area. Solid waste may be landfilled in layers of not more than two feet prior to compaction.

ARIZONA (53)

In addition to having ambient air quality standards Arizona has source emissions standards for particulates, sulfur compounds, and volatile organic compounds. These values are presented in Tables 88 and 89. State goals for ultimate achievement have also been established. They are included in Table 88.

Water standards are established for surface waters with specific uses. Applicable standards for domestic and industrial waters are compiled in Table 90.

Solid waste legislation lags behind the other areas. Daily landfill covers 6 to 12 inches are required. The final cover must be a minimum of two feet deep.

TABLE 86. EMISSIONS STANDARDS FOR INDUSTRIAL
PROCESSES AND FUEL BURNING EQUIPMENT IN ALASKA

Visible Emissions	20% opacity+	
Particulate Matter (coal burning equipment)	4.24 mg/m ³	(0.05 grain/ft ³)
Sulfur Compounds (as SO ₂)	500 ppm	

+denotes that the standard may not be exceeded for a total of more than three minutes in any hour.

TABLE 87. WATER QUALITY CRITERIA OF ALASKA

Parameter	Water Classification	
	Potable Water	Industrial Water
Dissolved Oxygen	75% saturation or 5 mg/l = 0.29 grain/gal	5 mg/l = 0.29 grain/gal for surface water
pH and (pH change)	6.5-8.5 (0.5 units)	6.5-8.5 (0.5 units)
Turbidity	5 JTU	No interference with water supply treatment
Temperature	16°C = 60°F	21°C = 70°F
Dissolved Inorganic Substances	500 mg/l = 29 grain/gal	low enough to prevent corrosion, scaling and process problems
Residues, Oils, Grease, Sludges, Other Physical and Chemical Criteria	essentially free from; may not exceed 1962 USPHS Standards (see Table 87)	No visible evidence of residue, may not impact public health

TABLE 88. AMBIENT AIR QUALITY STANDARDS OF ARIZONA

Constituents	Concentration		Remarks
	Metric	English	
Particulates	60 ug/m ³	7.1x10 ⁻⁴ grain/yd ³	A.G.M.
	150 ug/m ³	1.8x10 ⁻³ grain/yd ³	24 hr max
Sulfur Dioxide	50 ug/m ³	6.0x10 ⁻⁴ grain/yd ³	1 yr max
	260 ug/m ³	3.1x10 ⁻³ grain/yd ³	1 day max
	1300 ug/m ³	1.5x10 ⁻² grain/yd ³	3 hr max
Non-Methane Hydrocarbons	160 ug/m ³	1.9x10 ⁻³ grain/yd ³	3 hr max (6-9 A.M.)
Photochemical Oxidants	160 ug/m ³	1.9x10 ⁻³ grain/yd ³	1 hr max
Carbon Monoxide	40 mg/m ³	0.47 grain/yd ³	1 hr max
	10 mg/m ³	0.12 grain/yd ³	8 hr max
Nitrogen Dioxide	100 ug/m ³	1.2x10 ⁻³ grain/yd ³	1 yr max

Air Quality Goals

Constituent	Metric	English	Remarks
Particulates	100 ug/m ³	1.2x10 ⁻³ grain/yd ³	24 hr max
Non-Methane Hydrocarbons	80 ug/m ³	9.4x10 ⁻⁴ grain/yd ³	3 hr max (6-9 A.M.)
Carbon Monoxide	7 mg/m ³	0.083 grain/yd ³	8 hr max
Photochemical Oxidants	80 ug/m ³	9.4x10 ⁻⁴ grain/yd ³	1 hr max

Standard Conditions:

Temperature = 16°C = 60°F

Pressure = 1.03 kg/cm² = 14.7 psi

TABLE 89. INDUSTRIAL EMISSIONS STANDARDS IN ARIZONA

Particulate Emissions - Process Industries - General

$$E = 55.0 \, p^{0.11-40} \quad (E = 17.31 \, p^{0.16} \text{ for Phoenix-Tucson Air Quality Control Region})$$

where

E = max allowable emissions rate (lb m/hr)
P = process weight rate (ton m/hr)

For commercial SRC plants

$$E = 55.0 \frac{20,000 \text{ ton/day}}{(24 \text{ hr/day})} p^{11-40} = 75.2 \text{ lb m/hr} = 165.4 \text{ kg/hr}$$

$$E = 17.31 \, p^{0.16} = 50.8 \text{ lb m/hr} = 111.9 \text{ kg/hr (Phoenix-Tucson)}$$

Sulfur - other industries

Requirement: a minimum of 90% removal

Storage of volatile organic compounds

(for storage capacities of 65,000 gallons or greater)

Requirement = A floating roof is required for compounds with vapor pressures greater than 2 lb/in² but less than 12 lb/in². Equipment of equal efficiency may be substituted. The pressure range in metric units is from 0.1406 kg/cm² to 0.8436 kg/cm².

TABLE 90. ARIZONA WATER QUALITY CRITERIA

Substance	Limiting Concentration	
	mg/l	grain/gallon
Arsenic	0.05	0.0029
Barium	1.0	0.0584
Cadmium	0.01	0.0006
Chromium (Hexavalent)	0.05	0.0029
Copper	1.0	0.0584
Cyanide	0.2	0.0117
Mercury	0.005	0.0003
Lead	0.05	0.0029
Phenol	0.001	5.8×10^{-5}
Selenium	0.01	0.0006
Silver	0.05	0.0029
Zinc	5.0	0.2921

For waters supporting aquatic life the following standards exist:

pH: 6.5 to 8.6 with no discharge causing a change in pH of more than 0.5 pH units.

Temperature: maximum temperature = 34°C = 93°F
 maximum temperature increase = 2.8°C = 5°F

COLORADO (53)

Colorado has enacted standards of performance for new stationary sources. Of these, the standards of performance for petroleum refineries is probably most indicative of future legislation. These standards are reviewed in Table 91. Of particular interest in Colorado legislation pertaining to oil-water separators. SRC pilot plants use similar equipment. One or more of the following vapor loss controls is required: a solid cover, a floating roof, a vapor recovery system, or special equipment which can demonstrate equal or superior efficiency.

Both effluent limitations and water quality standards have been promulgated. As Table 92 shows, the standards are stringent for all classes of water. Effluent limitations also are presented in Table 93. Solid waste requirements are not as rigorous. Compaction of wastes is required.

INDIANA (53)

In addition to legislating ambient air quality standards (Table 94) Indiana has laws controlling the storage and handling of volatile hydrocarbon liquids. A vapor recovery system, floating roof or alternative system which meets approval of the proper state agencies is required. Volatile organic liquid - water separators require either a solid cover or one of the vapor control methods required for storage systems.

Indiana water quality standards state criteria to be considered when determining a mixing zone but prescribe no absolute zone, reasoning that too many variables are involved. Pertinent water quality criteria are outlined in Table 95.

Prior to the issuing of permits to operate landfills, a detailed plan of the operation must be submitted to and approved by the appropriate state agencies.

TABLE 91. STANDARDS OF PERFORMANCE FOR PETROLEUM
REFINERIES IN COLORADO

Particulates

1 kg/metric ton = 1 lb/1000 lb

30% opacity for greater than 3 minutes in any hour is not allowed.
Failure to comply due to uncombined water is not a violation.

Carbon Monoxide

Discharge gases may not contain greater than 0.050% carbon
monoxide by volume.

Sulfur Dioxide

Emissions may not exceed those resulting from fuel gas containing
230 mg/dscm (0.10 grain/dscf) of hydrogen sulfide.

TABLE 92. COLORADO WATER QUALITY STANDARDS

Standard	<u>Water Classification</u>			
	A1	A2	B1	B2
Settleable Solids, Floating Solids, Taste, Odor, Color, and Toxic Materials	Free From	Free From	Free From	Free From
Oil and Grease	No film or discoloration	No film or discoloration	No film or discoloration	No film or discoloration
Turbidity Increase	10 J.T.U.	10 J.T.U.	10 J.T.U.	10 J.T.U.
Dissolved Oxygen (minimum)	6 mg/l 0.35 grain/ gallon	5 mg/l 0.29 grain/ gallon	6 mg/l 0.35 grain/ gallon	5 mg/l 0.29 grain/ gallon
pH Range	6.5-8.5	6.5-8.5	6.0-9.0	6.0-9.0
Temperature, Maximum	20°C 68°F	32°C 90°F	20°C 68°F	32°C 90°F
Temperature		<u>Streams</u>		<u>Streams</u>
Maximum Increase	1.1°C 2°F	2.8°C 5°F	1.1°C 2°F	2.8°C 5°F
		<u>Lakes</u>		<u>Lakes</u>
		1.7°C 3°F		1.7°C 3°F

TABLE 93. COLORADO EFFLUENT DISCHARGE CRITERIA

<u>Parameter</u>	<u>7 day avg.</u>		<u>30 day avg.</u>	
	mg/l	grain/gal.	mg/l	grain/gal.
BOD ₅	45	2.63	30	1.75
Suspended Solids	45	2.63	30	1.75
Residual Chlorine	0.5 mg/l = 0.03 grain/gal.			
Oil and Grease	10 mg/l = 5.84 grain/gal.			
pH range	6.0-9.0			

ILLINOIS (53)

Comprehensive air and water standards have been promulgated by the Illinois Pollution Control Board. New fuel combustion emissions sources encompassing sulfur dioxide, nitrogen oxides, carbon monoxide, fugitive particulate matter and particulate emissions are listed in Table 96. Regulations regarding the emissions of organic materials from oil/water separators, storage tanks, and loading operations have also been adopted. Air quality standards for Illinois are given in Table 97.

Water quality standards and effluent standards are given in Tables 98 and 99, respectively. The rules and regulations indicate that dilution of the effluent from a treatment works or from any wastewater source is not acceptable as a method of treatment of wastes in order to meet the effluent standards. It is further stated, that the most technically feasible and economically reasonable treatment methods should be employed to meet the effluent limitations specified in Table 99.

Treated effluents are expected not to exceed 30 mg/l BOD₅ and 37 mg/l suspended solids.

KENTUCKY (53)

Air quality standards are listed in Table 100. Note that Kentucky has a standard for hydrogen sulfide as well as for sulfur dioxide. The standards of performance for petroleum refineries have been compiled in Table 101.

Kentucky water quality standards vary with stream use classification. Table 102 shows the most stringent standards, which would be applicable in a multiple-use situation. Solid waste requirements include providing more than two feet of compacted soil between solid waste and maximum water table, two feet or more of compacted earth between solid waste and bedrock, solid waste layers of two to three feet and a final daily cover of six inches to prevent waste dispersion. A final cover of two feet of compacted soil is required, to be followed by revegetation.

TABLE 94. INDIANA AMBIENT AIR QUALITY STANDARDS

Constituent	Concentration		Remarks
	Metric	English	
Sulfur Dioxide			
primary	80 ug /m ³	9.4x10 ⁻⁴ grain/yd ³	A.A.M.
	365 ug /m ³	4.3x10 ⁻³ grain/yd ³	24 hr max*
secondary	60 ug /m ³	7.1x10 ⁻³ grain/yd ³	A.A.M.
	260 ug /m ³	3.1x10 ⁻³ grain/yd ³	24 hr max*
	1100 ug /m ³	1.3x10 ⁻² grain/yd ³	1 hr max*
Particulates			
primary	75 ug /m ³	8.8x10 ⁻⁴ grain/yd ³	A.G.M.
	260 ug /m ³	3.1x10 ⁻³ grain/yd ³	24 hr max*
secondary	60 ug /m ³	7.1x10 ⁻⁴ grain/yd ³	A.G.M.
	150 ug /m ³	1.8x10 ⁻³ grain/yd ³	24 hr max*
Carbon Monoxide			
primary and	10 mg/m ³	0.12 grain/yd ³	8 hr max*
secondary	40 mg/m ³	0.47 grain/yd ³	1 hr max*
Photochemical Oxidants			
primary and	160 ug /m ³	1.9x10 ⁻³ grain/yd ³	1 hr max*
secondary			
Hydrocarbons			
primary and	160 ug /m ³	1.9x10 ⁻³ grain/yd ³	3 hr max*
secondary			(6-9 A.M.)
Nitrogen Dioxide			
primary and	100 ug /m ³	1.2x10 ⁻³ grain/yd ³	A.A.M.
secondary			

Reference Conditions: Temperature = 25°C = 77°F
 Pressure = 760 mmHg = 14.7 psi = 1 atmosphere

TABLE 95. WATER QUALITY CRITERIA OF INDIANA

pH: between 6.0 and 8.5

Toxic Substances: shall not exceed one-tenth of the 96-hour median tolerance limit

Dissolved Oxygen: 5 mg/l daily average, never less than 4 mg/l (equivalent to 0.2921 grain/gal and 0.2336 grain/gal respectively)

Temperature: Maximum Values Allowed

<u>Month</u>	<u>Ohio River</u>		<u>St. Joseph River</u>		<u>Others</u>	
	°C	°F	°C	°F	°C	°F
January	10	50	10	50	10	50
February	10	50	10	50	10	50
March	16	60	13	55	16	60
April	18	70	18	65	18	70
May	27	80	24	75	27	80
June	31	87	29	85	32	90
July	32	89	29	85	32	90
August	32	89	29	85	32	90
September	31	87	29	85	32	90
October	26	78	18	70	26	78
November	18	20	16	60	18	70
December	14	57	10	50	14	57

Maximum Temperature Rise is: 2.8 °C = 5°F for streams

1.7 °C = 3°F for lakes and reservoirs

(Note: certain parameters are more stringent for waters where natural reproduction of trout and salmon is to be protected.

TABLE 96. APPLICABLE ILLINOIS EMISSIONS REGULATIONS

New Fuel Combustion Emission Sources

Sulfur Dioxide

For actual heat input ≥ 250 M BTU/hr resulting from the burning of solid fuel exclusively, SO₂ emissions must not exceed 1.2 lb/M BTU.

Nitrogen Oxide

For actual heat input ≥ 250 M BTU/hr resulting from the burning of solid fuel exclusively, NO emissions must not exceed 0.7 lb/M BTU.

Carbon Monoxide

For actual heat input ≥ 10 M BTU/hr, CO emissions must not exceed 200 ppm corrected to 50 percent excess air.

Fugitive Particulate Matter

Emissions should not exceed 0.1 lb/M BTU actual heat input using solid fuel exclusively over a period of one hour.

Particulates

Discharge of particulates from new process sources during a one hour period shall not exceed the allowable emission rates specified by the following equations:

$$\begin{array}{ll} \text{Process weight rate} \leq & 450 \text{ tons/hr} \\ & E = 2.54 (P)^{0.534} \end{array}$$

$$\begin{array}{ll} \text{Process weight rate} & 450 \text{ tons/hr} \\ & E = 24.8 (P)^{0.16} \end{array}$$

where

E = allowable emission rate in pounds/hour

P = process weight rate in tons/hour

Waste Gas Disposal

Organics

Emissions from any petroleum or petrochemical manufacturing process should not exceed 100 ppm equivalent methane.

TABLE 97. ILLINOIS AIR QUALITY STANDARDS
FOR PARTICULATE MATTER

<u>Standard</u>	<u>Concentrations</u>	
	Annual Geometric Mean	Max. 24 hour*
Primary		
$\mu\text{g}/\text{m}^3$	75	260
grain/yd ³	9.0×10^{-4}	3.1×10^{-3}
Secondary		
$\mu\text{g}/\text{m}^3$	60	150
grain/yd ³	7.1×10^{-4}	1.8×10^{-3}

*Not to be exceeded more than once per year.

TABLE 98. ILLINOIS WATER QUALITY STANDARDS

CONSTITUENT	STORET NUMBER	CONCENTRATION (Mg/l)
Ammonia Nitrogen (as N)	00610	1.5
Arsenic (total)	01000	1.0
Barium (total)	01005	5.0
Boron (total)	01020	1.0
Cadmium (total)	01025	0.05
Chloride	00940	500.
Chromium (total hexavalent)	01032	0.05
Chromium (total trivalent)	01033	1.0
Copper (total)	01040	0.02
Cyanide	00720	0.025
Fluoride	00950	1.4
Iron (total)	01045	1.0
Lead (total)	01049	0.1
Manganese (total)	01055	1.0
Mercury (total)	71900	0.0005
Nickel (total)	01065	1.0
Phenols	32730	0.1
Selenium (total)	01145	1.0
Silver (total)	01075	0.005
Sulfate	00945	500.
Total Dissolved Solids	00515	1000.
Zinc	01090	1.0

TABLE 99. ILLINOIS EFFLUENT STANDARDS

CONSTITUENT	CONCENTRATION (mg/l)
Arsenic (total)	0.25
Barium (total)	2.0
Cadmium (total)	0.15
Chromium (total hexavalent)	0.3
Chromium (total trivalent)	1.0
Copper (total)	1.0
Cyanide	0.025
Fluoride (total)	15.0
Iron (total)	2.0
Iron (dissolved)	0.5
Lead (total)	0.1
Manganese (total)	1.0
Mercury (total)	0.0005
Nickel (total)	1.0
Oil (hexane solubles or equivalent)	15.0
pH	range 5-10*
Phenols	0.3
Selenium (total)	1.0
Silver	0.1
Zinc (total)	1.0
Total Suspended Solids (from sources other than those covered by Rule 404)	15.0
Total Dissolved Solids	**

*The pH limitation is not subject to averaging and must be met at all times.

**Total Dissolved Solids (STORET Number 00515) shall not be increased more than 750 mg/l above background concentration levels unless caused by recycling or other pollution abatement practices, and in no event shall exceed 3500 mg/l at any time; provided, however, this Rule shall not apply to any effluent discharging to the Mississippi River, which, after mixing as set forth in Rule 201, meets the applicable water quality standard for Total Dissolved Solids.

TABLE 100. AMBIENT AIR QUALITY STANDARDS IN KENTUCKY

Constituent	Concentration		Remarks
	Metric	English	
Sulfur Dioxide			
primary	80 ug/m ³	9.4x10 ⁻⁴ grain/yd ³	A.A.M.
	365 ug/m ³	4.3x10 ⁻³ grain/yd ³	24 hr max*
secondary	1300 ug/m ³	1.5x10 ⁻² grain/yd ³	3 hr max*
Particulates			
primary	75 ug/m ³	8.8x10 ⁻⁴ grain/yd ³	A.G.M.
	260 ug/m ³	3.1x10 ⁻³ grain/yd ³	24 hr max*
secondary	60 ug/m ³	7.1x10 ⁻⁴ grain/yd ³	A.G.M.
	150 ug/m ³	1.8x10 ⁻³ grain/yd ³	24 hr max*
Particulates (Soiling Index)			
primary	19.7 COH/1000 LM	6.0 COH/1000 LF	24 hr max*
secondary	1.3 COH/1000 LM	0.4 COH/1000 LF	A.A.M.
	1.6 COH/1000 LM	0.5 COH/1000 LF	3 month max
	1.0 COH/1000 LM	0.3 COH/1000 LF	24 hr max*
Carbon Monoxide			
primary and secondary	10 ug/m ³	0.12 grain/yd ³	8 hr max*
	40 ug/m ³	0.47 grain/yd ³	1 hr max*
Photochemical Oxidants			
standard	160 ug/m ³	1.9x10 ⁻³ grain/yd ³	1 hr max*
Hydrocarbons			
standard	160 ug/m ³	1.9x10 ⁻³ grain/yd ³	3 hr max* (6-9 A.M.)
Nitrogen Dioxide			
standard	100 ug/m ³	1.2x10 ⁻³ grain/yd ³	A.A.M.

TABLE 100. AMBIENT AIR QUALITY STANDARDS IN KENTUCKY
(Continued)

Constituent	Concentration		Remarks
	Metric	English	
Hydrogen Sulfide			
standard	14 ug/m ³	1.7x10 ⁻⁴ grain/yd ³	1 hr max*
Gaseous Fluoride (HF)			
primary	0.82 ug/m ³	9.7x10 ⁻⁶ grain/yd ³	1 month max*
	1.64 ug/m ³	1.9x10 ⁻⁵ grain/yd ³	1 week max*
	2.86 ug/m ³	3.4x10 ⁻⁵ grain/yd ³	1 day max*
	3.68 ug/m ³	4.3x10 ⁻⁵ grain/yd ³	12 hr max*
Total Fluorides			
primary		40 ppm	6 month avg.
		60 ppm	2 month avg.
		80 ppm	1 month avg.

Reference Conditions: Temperature - 25°C = 77°F

Pressure = 760 mm Hg = 29.92 in Hg = 1 atm.

TABLE 101. STANDARDS OF PERFORMANCE FOR PETROLEUM
REFINERIES IN KENTUCKY

Particulates

1.0 kg/metric ton feed

1.0 lb/1000 lb feed

Carbon Monoxide

0.050% by volume

Sulfur Dioxide

Emissions may not exceed the equivalent of combustion of fuel gas
containing 230 mg/dscm of hydrogen sulfide.

(230 mg/dscm = 0.10 grain/dscf)

TABLE 102. KENTUCKY WATER QUALITY STANDARDS

<u>Constituent</u>	<u>Concentration</u>	
	<u>mg/l</u>	<u>grain/gallon</u>
Arsenic	0.05	0.0029
Barium	1.0	0.0584
Cadmium	0.01	5.84×10^{-4}
Chromium (hexavalent)	0.05	0.0029
Cyanide	0.025	0.0015
Fluoride	1.0	0.0584
Lead	0.05	0.0029
Selenium	0.01	5.84×10^{-4}
Silver	0.05	0.0029

Dissolved Oxygen: 5 mg/l = 0.2921 grain/gallon daily average
never the less than 4 mg/l = 0.2336 grain/gallon

Dissolved Solids: 500 mg/l = 29.21 grain/gal monthly average
never more than 700 mg/l = 40.89 grain/gallon

Temperature: never to exceed 32°C = 89°F

Maximum Temperature Rise: 2.8°C = 5°F for streams, 1.7°C = 3°F for epilimnion
of thermally stratificated waters

Maximum Monthly Temperature:

<u>Month</u>	<u>Jan.</u>	<u>Feb.</u>	<u>Mar.</u>	<u>Apr.</u>	<u>May</u>	<u>June</u>	<u>July</u>	<u>Aug.</u>	<u>Sept.</u>	<u>Oct.</u>	<u>Nov.</u>	<u>Dec.</u>
°C	10	10	16	21	27	31	32	32	31	27	21	14
°F	50	50	60	70	80	87	89	89	87	78	70	57

MONTANA (53)

Montana has adopted the federal new source performance standards to supplement its own ambient air quality standards. Applicable ambient standards are presented in Table 103.

Water quality policy consists of general water quality criteria and specific water quality criteria which correspond to the various water-use classifications. Table 104 describes criteria for the most and least stringent classifications to given in an idea of the range of conditions permitted.

Site approval is required for solid waste disposal when hazardous wastes are involved. A daily cover of six inches and final cover of two feet or more are also required. Disposal sites shall not be located near springs or other water supplies, near geologic formations which could cause leaching problems, in areas of high groundwater tables or within the boundaries of 100-year flood plains.

NEW MEXICO (53)

New Mexico is presently the only state that has promulgated emissions standards applicable to coal conversion facilities, specifically coal gasification plants. Stacks at least ten diameters tall and equipped with enough sampling ports and platforms to perform accurate sampling are required. Particulate emissions requirements exist for briquet forming areas, coal preparation areas, and the gasification plant itself - with an additional requirement for gas burning boilers. Limits have been placed on dischargeable concentrations of sulfur, hydrocarbons, ammonia, hydrogen chloride, hydrogen cyanide, hydrogen sulfide, carbon disulfide, and carbon oxysulfide as well. These limits are compiled in Table 105.

These are stringent criteria, relative to most of the states reviewed. However a review of New Mexico air laws pertaining to petroleum refineries reflects an interest in environmental preservation, not a distrust of new technology. Emissions standards for ammonia and hydrogen sulfide, for example, are the same for both industries. In fact, refineries have additional limits on mercaptan and carbon

TABLE 103. AMBIENT AIR QUALITY STANDARDS IN MONTANA

Constituent	Concentration		Remarks
Sulfur Dioxide	0.02 ppm		A.A.M.
	0.10		(1)
	0.25		(2)
Hydrogen Sulfide	0.03 ppm		(3)
	0.05 ppm		(4)
Fluorides	1.0 ppb		24 hr max
	<u>Metric</u>	<u>English</u>	
Settled Particulates	5.26 kg/km ² /month	15 ton/mi ² /month	(5)
	10.53 kg/km ² /month	30 ton/mi ² /month	(6)
Reactive Sulfur	0.25 mg/100cm ² /day	0.036 grain/ft ² /day	A.A.M.
(SO ₃)	0.50 mg/100cm ² /day	0.072 grain/ft ² /day	1 month max
	<u>Metric (ug/m³)</u>	<u>English (grain/yd²)</u>	
Total Suspended	75	8.8 x 10 ⁻⁴	A.G.M.
Particulates	200	2.4 x 10 ⁻³	(7)
Suspended Sulfate	4.0	4.7 x 10 ⁻⁵	A.A.M.
	12.0	1.4 x 10 ⁻⁴	(8)
Sulfuric Acid Mist	4.0	4.7 x 10 ⁻⁵	A.A.M.
	12.0	1.4 x 10 ⁻⁴	(8)
	30.0	3.5 x 10 ⁻⁴	1 hr max (8)
Lead	5.0	5.9 x 10 ⁻⁵	3 day max

- (1) Not to be exceeded over 1% of the days in avg. 3 month period
- (2) Not to be exceeded for more than one hour in avg. 4 consecutive days
- (3) Not to be exceeded more than twice in avg. five consecutive days
- (4) Not to be exceeded more than twice per year
- (5) 3 month average - residential areas
- (6) 3 month average - industrial areas
- (7) Not to be exceeded more than 1% of the days in avg. year
- (8) Not to be exceeded more than 1% of the time

TABLE 104. SELECTED WATER QUALITY CRITERIA OF MONTANA

<u>Parameter</u>	<u>E-F Classification</u>		<u>A-Closed Classification</u>
	<u>Metric</u>	<u>English</u>	
Dissolved Oxygen (minimum value)	3 mg/l	0.18 grain/gal	No decrease allowed
pH		6.5-9.5	No change allowed
pH variation allowed		0.5 pH units	Not allowed
Turbidity, Temperature, Sediments		Shall cause no adverse effects	No increase allowed
Toxic/Deleterious Substances		Less than demonstrated hazardous concentration	No increase allowed

Additionally, Montana waters shall comply with the 1962 U.S. Public Health Service Drinking Water Standards (see Table 48).

TABLE 105. NEW MEXICO EMISSIONS STANDARDS
FOR COMMERCIAL GASIFIERS

Constituent/Operation	Standard		Remarks
	Metric	English	
Particulates			
Briquetting	69 mg/scm	0.03 grain/scf	
General Operations	69 mg/scm	0.03 grain/scf	
Gas Burning Boilers	0.054 kg/10 ⁶ Kcal	0.03 lb/10 ⁶ Btu	Based on heat input to boiler
Hydrogen Sulfide, Carbon Disulfide, Carbon Oxysulfide (Any Combination)			
General Operations		100 ppm (Total) 10 ppm (Hydrogen Sulfide)	All ppm by volume
Hydrogen Cyanide			
General Operations		10 ppm	
Hydrogen Chloride			
General Operations		5 ppm	
Ammonia			
General Operations		25 ppm	
Storage			Vapor control required
Sulfur Dioxide			
Gas Burning Boilers	0.29 kg/10 ⁶ kcal	0.16 lb/10 ⁶ Btu	Based on heat input to boiler
Sulfur			
General Operations	0.014 kg/10 ⁶ kcal	0.008 lb/10 ⁶ Btu	Based on heat input of feed

TABLE 105. NEW MEXICO EMISSIONS STANDARDS FOR
COMMERCIAL GASIFIERS (Continued)

Hydrocarbons

Storage - For a vapor pressure greater than 0.1055 kg/cm^2 (1.5 psi),
a floating roof, vapor recovery and disposal system or
equivalent control technology is required.

Loading Systems - Vapor collection adapters are required.

monoxide not presently included in gasification legislation. These requirements as well as the New Mexico Ambient Air Quality Standards are presented in Table 106. The ambient air criteria for heavy metals and the difference in dischargeable carbon monoxide concentrations between new and existing refineries should be noted. Water quality standards are specific. For example, the Rio Grande Basin is divided into fifteen sections, each with independent water quality standards. Table 107 presents applicable water quality criteria for selected areas.

Solid waste regulation is not as advanced or as complicated as air and water controls. State requirements include six inches of daily cover, compaction of wastes to smallest practical volume, and a minimum final cover of two feet of earth. Landfill bottoms must be a minimum of 20 feet above groundwater level.

NORTH DAKOTA (53)

Table 108 describes the applicable ambient air quality standards of North Dakota. These have been established in accordance with the state air quality guidelines which call for preservation of the health of the general public, plant and animal life, air visibility and natural scenery. The guidelines also require that ambient air properties not change in any way which will increase corrosion rates of metals or deterioration rates of fabrics. Additionally, emissions restrictions from industrial processes exist for particulates and sulfur oxides. Sulfur dioxide emissions are limited to three pounds per million Btu of heat input.

Water quality is dependent upon water classification. Applicable criteria for Class I waters are discussed in Table 109. Mixing zone guides are described in preference to defining a mixing zone applicable to every situation.

North Dakota regulations specify a daily cover of six inches and a final cover of twelve inches for sanitary landfill operations.

TABLE 106. AMBIENT AIR QUALITY STANDARDS IN NEW MEXICO

Constituent	Concentration		Remarks
	Metric	English	
Particulates	150 ug/m ³	1.8x10 ⁻³ grain/yd ³	1 day max
	110 ug/m ³	1.3x10 ⁻³ grain/yd ³	7 day max
	90 ug/m ³	1.1x10 ⁻³ grain/yd ³	30 day max
	60 ug/m ³	7.1x10 ⁻⁴ grain/yd ³	A.G.M.
Heavy Metals	10 ug/m ³	1.2x10 ⁻⁴ grain/yd ³	
Soiling Index	1.3 COH/1000 LM	0.4 COH/1000 LF	
Sulfur Dioxide	0.10 ppm		24 hr max
	0.02 ppm		A.A.M.
Hydrogen Sulfide	0.003 ppm		1 hr max
	0.100 ppm		1/2 hr max (1)
Total Reduced Sulfur	0.003 ppm		1 hr max
Carbon Monoxide	8.7 ppm		8 hr max
	13.1 ppm		1 hr max
Nitrogen Dioxide	0.10 ppm		24 hr max
	0.05 ppm		A.A.M.
Photochemical Oxidants	0.10 ppm		24 hr max
	0.05 ppm		A.A.M.

(1) This standard applies to the Pecos-Permian Basin Intrastate Air Quality Control Region.

Emissions Standards for Refineries

Constituent	Concentration		Remarks
	Metric	English	
Mercaptan	0.11 kg/hr	0.25 lb/hr	
Carbon Monoxide	500 ppm		new facilities
	20,000 ppm		existing facilities

TABLE 107. NEW MEXICO WATER QUALITY CRITERIA

Parameter	Rio Grande Basin Section		San Francisco River Basin Section		
	<u>1</u>	<u>6</u>	<u>10</u>	<u>1</u>	<u>3</u>
Dissolved Oxygen, mg/l	5.0	6.0 (1)	6.0 (1)	5.0	6.0 (1)
Dissolved Oxygen, grain/gallon	0.29	0.35(1)	0.35(1)	0.29	0.35(1)
pH Range	6.6-8.8	6.6-8.8	6.6-8.8	6.6-8.8	6.6-8.8
Temperature, °C	34	20	20	32.2	20
Temperature, °F	93.2	68	68	90	68
Total Dissolved Solids, mg/l	2000				
Total Dissolved Solids, grain/gallon	116.8				
Sulfates, mg/l	500				
Sulfates, grain/gallon	29.2				
Organic Carbon, mg/l			70		7.0
Organic Carbon, grain/gal			0.41		0.41

(1) 85% of saturation is alternatively allowable.

TABLE 108. AMBIENT AIR QUALITY STANDARDS OF NORTH DAKOTA

Constituent	Concentration		Remarks
	Metric	English	
Particulates	60 ug/m ³	7.1x10 ⁻⁴ grain/yd ³	A.G.M.
	150 ug/m ³	1.8x10 ⁻³ grain/yd ³	24 hr max*
Sulfur Dioxide	60 ug/m ³	7.1x10 ⁻⁴ grain/yd ³	A.A.M.
	260 ug/m ³	3.1x10 ⁻³ grain/yd ³	24 hr max
	715 ug/m ³	8.4x10 ⁻³ grain/yd ³	1 hr max
Hydrogen Sulfide	45 ug/m ³	5.3x10 ⁻⁴ grain/yd ³	1/2 hr max (1)
	75 ug/m ³	8.8x10 ⁻⁴ grain/yd ³	1/2 hr max (2)
Carbon Monoxide	10 mg/m ³	0.12 grain/yd ³	8 hr max*
	40 mg/m ³	0.47 grain/yd ³	1 hr max*
Photochemical Oxidants	160 ug/m ³	1.9x10 ⁻³ grain/yd ³	1 hr max*
Hydrocarbons	160 ug/m ³	1.9x10 ⁻³ grain/yd ³	1 hr max*
Nitrogen Dioxide	100 ug/m ³	1.2x10 ⁻³ grain/yd ³	A.A.M.
	200 ug/m ³	2.4x10 ⁻³ grain/yd ³	1 hr max (3)
Particulates (dustfall)	5.27 kkg/km ² /month	15 ton/mi ² /month	3 month max (4)
	10.53 kkg/km ² /month	30 ton/mi ² /month	3 month max (5)
Soiling Index	1.3 COH/1000 LM	0.4 COH/1000 LF	

- (1) maximum concentration is not to be exceeded more than twice in avg. five days
- (2) maximum concentration is not to be exceeded more than twice per year
- (3) maximum concentration is not to be exceeded more than one percent of the time in any three month period
- (4) applicable to residential areas
- (5) applicable to industrial areas

Reference Conditions: Temperature = 25°C = 77°F
 Pressure = 760 mmHg = 29.2 in Hg = 1 atm.

TABLE 109. CLASS I WATER QUALITY STANDARDS IN NORTH DAKOTA

Parameter	Maximum Allowable Concentration or Range	
	Metric (mg/l)	English (grain/gallon)
Ammonia	1.0	0.0584
Arsenic	0.05	0.0029
Barium	1.0	0.0584
Boron	0.5	0.0292
Cadmium	0.01	5.84×10^{-4}
Chlorides	100.0	5.8
Chromium (Total)	0.05	0.0029
Copper	0.05	0.0029
Cyanides	0.01	5.84×10^{-4}
Dissolved Oxygen (minimum)	5.0	0.2921
Lead	0.05	0.0029
Nitrates	4.0	0.2326
Phenols	0.01	5.84×10^{-4}
Phosphates	0.1	0.0058
Selenium	0.01	5.84×10^{-4}
Total Dissolved Solids	500.0	29.2
Zinc	0.5	0.0292
Temperature Increase	2.8°C	5°F
Maximum Temperature	29.4°C	85°F
pH	7.0-8.5	
Turbidity Increase	10 JTU	

Sodium: 50% of total cations as milliequivalents/liter

OHIO (53)

Ohio legislation to preserve air quality includes both ambient and emission standards. Ambient standards are in Table 110. Emissions regulations for industrial processes have been promulgated for particulates, sulfur oxides, nitrogen oxides, hydrocarbons, carbon monoxide and photochemical oxidants. Priority zones also have been established. These zones presently do not meet EPA standards for sulfur dioxide, nitrogen dioxide, and particulates. The sulfur dioxide and particulates emissions limits are mathematical functions of total emissions discharged and process throughput, respectively. Carbon monoxide from petroleum refinery processes must go through an afterburner prior to discharge. Standards for storage of hydrocarbons are in line with those previously mentioned. Photochemical oxidants must be incinerated to a minimum of 90 percent oxidation prior to discharge to the atmosphere.

Effluent discharge requirements vary. Water quality standards depend on water use and mixing zone which is formulated for specific discharges and locations rather than a generalized definition. Criteria for public water supply, the most stringent classification, are highlighted in Table 116. Dissolved oxygen and pH levels for streams supporting aquatic life are included. Table 112 describes general standards.

Plans for all sanitary landfill sites and operations must be approved in advance. A complete description of site terrain and subterrain must be supplied as well as soil chemistry and local hydrology data. A six inch daily cover and a two foot final compacted soil cover also are required. Semi-annual well monitoring for chlorides, chemical oxygen demand, total organic carbon and total dissolved solids is an additional requirement.

PENNSYLVANIA

Hydrocarbon emissions are limited by controls requiring either a vapor recovery system or floating roof for storage tanks, the former required for hydrocarbon loading equipment, the latter for hydrocarbon-water separators. Applicable ambient standards are shown in Table 113.

TABLE 110. OHIO AMBIENT AIR QUALITY STANDARDS

Constituent	Concentration		Remarks
	Metric	English	
Particulates	60 $\mu\text{g}/\text{m}^3$	7.1×10^{-4} grain/ yd^3	A.G.M.
	150 $\mu\text{g}/\text{m}^3$	1.8×10^{-3} grain/ yd^3	24 hr max*
Sulfur Dioxide	60 $\mu\text{g}/\text{m}^3$	7.1×10^{-4} grain/ yd^3	A.G.M.
	260 $\mu\text{g}/\text{m}^3$	3.1×10^{-3} grain/ yd^3	24 hr max*
Carbon Monoxide	10 mg/m^3	0.12	8 hr max*
Photochemical Oxidants	119 $\mu\text{g}/\text{m}^3$	1.4×10^{-3} grain/ yd^3	1 hr max
	79 $\mu\text{g}/\text{m}^3$	9.5×10^{-4} grain/ yd^3	4 hr max (1)
	40 $\mu\text{g}/\text{m}^3$	4.7×10^{-4} grain/ yd^3	24 hr max*
Hydrocarbons	126 $\mu\text{g}/\text{m}^3$	1.5×10^{-3} grain/ yd^3	3 hr max (2)
	331 $\mu\text{g}/\text{m}^3$	4.0×10^{-3} grain/ yd^3	24 hr max*
Nitrogen Dioxide	100 $\mu\text{g}/\text{m}^3$	1.2×10^{-3} grain/ yd^3	A.A.M.

(1) denotes the maximum concentration shall not be exceeded more than one consecutive four hour period per year.

(2) denotes that ambient levels are to be monitored from 6 to 9 A.M.

Reference Conditions: Temperature = $21.1^\circ\text{C} = 70^\circ\text{F}$
 (dry gas) Pressure = $1.03 \text{ kg}/\text{cm}^2 = 14.7 \text{ psi}$

TABLE 111. OHIO STREAM QUALITY CRITERIA
FOR PUBLIC WATER SUPPLY USE

Constituent	Concentration	
	Metric (mg/l)	English (grain/gallon)
Arsenic	0.05	0.0029
Barium	1.0	0.0584
Cadmium	0.005	2.92×10^{-4}
Chromium (hexavalent)	0.05	0.0029
Cyanide	0.025	0.0015
Dissolved Oxygen (1)	5.0	0.2921
Dissolved Solids (2)	500	29.2
Fluoride	1.0	0.0584
Lead	0.05	0.0029
Mercury	0.005	2.92×10^{-4}
Selenium	0.005	2.92×10^{-4}
Silver	0.05	0.0029

(1) Dissolved oxygen concentrations are minimum values. The given values are averages. A value of 4.0 mg/l (0.2336 grain/gallon) is the minimum acceptable value. These values are for waters designated to support aquatic life.

(2) Value given is monthly average with a maximum allowable value of 750 mg/l (43.8 grain/gallon) never to be exceeded.

TABLE 112. GENERAL WATER STANDARDS APPLICABLE WITHIN
500 YARDS OF ANY PUBLIC WATER SUPPLY INTAKE IN OHIO

Constituent	Concentration Limit	
	Metric (mg/l)	English (grain/gallon)
Cyanide	0.005	2.92×10^{-4}
Dissolved Iron	0.3	0.0175
Dissolved Manganese	0.05	0.0029
Dissolved Oxygen (1)	5.0	0.2921
Dissolved Solids (2)	500	29.2
Hexavalent Chromium	0.01	5.84×10^{-4}
Nitrates	8.0	0.4673
Phenols	0.001	5.84×10^{-5}
pH Range	6.0-9.0	

(1) 5.0 mg/l (0.2921 grain/gallon) daily minimum average, never less than 4.0 mg/l (0.2336 grain/gallon).

(2) Dissolved solids level may exceed (a) or (b) but not both.

(a) 500 mg/l (29.2 grain/gallon) monthly average, never to exceed 750 mg/l (43.8 grain/gallon).

(b) 150 mg/l (8.8 grain/gallon) attributable to human activities.

TABLE 113. AMBIENT AIR QUALITY STANDARDS
OF PENNSYLVANIA

Constituent	Concentration		Remarks
	Metric	English	
Settled Particulates	0.8 ug/cm ² /month	grain/in ² /month	A.A.M.
	1.5 ug/cm ² /month	grain/in ² /month	30 day max
Lead	5.0 ug/m ³		30 day max
Sulfates	1.0 ug/m ³		30 day max
	3.0 ug/m ³		24 hr max
Fluorides	5.0 ug/m ³		24 hr max
		0.005 ppm	24 hr max
Hydrogen Sulfide		0.1 ppm	1 hr max

Standards for Contaminants

Particulates - unspecified process

For effluent gas discharge rates greater than 8500 dscm/min
(300,000 dscf/min), 458 mg/dscm (0.2 grain/dscf) is allowed.

Particulates - petroleum refineries

20 kg/metric ton (40 lb/ton) of liquid feed

Visible Emissions - unspecified process

Opacity equal to or greater than 20% is not allowed for aggregate periods of more than three minutes in any hour. Additionally, 60% opacity may never be exceeded. Opacity due to uncombined water mists is excluded in determining opacity levels.

Pennsylvania water quality criteria, based upon water use, are in Table 114. Applicable criteria are given for the Monogahela River; criteria differ for each stream, and, in many cases, for sections of the same stream.

The solid waste legislation of Pennsylvania is among the most extensive of any of the states considered. In addition to the general solid waste legislation, Pennsylvania has promulgated rules and regulations governing coal refuse disposal. These rules may be more indicative of future legislation regarding SRC generated residues. The rules are general, prohibiting disposal which will promote fire, subsidence, or leaching problems. The state also has published a statement or guidelines and acceptable procedures for the operation of such disposal areas. Generally, two feet of final cover are required. The landfill shall be a minimum of six feet above the seasonal high water table. Disposal cells may not exceed eight feet with compacted solid waste layers of two feet or less. Hazardous waste disposal plans must be approved by the appropriate state agencies.

SOUTH DAKOTA

The ambient air quality standards of South Dakota are shown in Table 115. South Dakota has reserved the right to set emissions standards for any source which may be exceeding the ambient standards. Standards for fuel burning installations and general process industries are listed in Table 116.

Water quality criteria for three types of waters are presented in Table 117. It is obvious that the intended water use provisions of several state laws, including South Dakota, will be an important point to consider in site selection for commercialized SRC facilities. Mixing zones are dependent on stream characteristics. Lakes are not allowed a mixing zone.

TABLE 114. WATER QUALITY STANDARDS FOR THE
MONONGAHELA RIVER IN PENNSYLVANIA

Parameter	Concentration	
	Metric	English
Dissolved Oxygen (1)	6.0 mg/l	0.3505 grain/gallon
Total Iron	1.5 mg/l	0.0876 grain/gallon
Maximum Temperature	30.6°C	87°F
Temperature Increase (2)	2.8°C	5°F
Dissolved Solids (3)	500 mg/l	29.2 grain/gallon
Total Manganese	1.0 mg/l	0.0584 grain/gallon
Phenols	0.005 mg/l	2.92×10^{-4} grain/gallon
pH Range	6.0-8.5	

- (1) 6.0 mg/l (0.3505 grain/gallon) is the minimum daily average.
5.0 mg/l (0.2921 grain/gallon) is the minimum acceptable level.
For the epilimnion of stream sections where thermal stratification occurs, the minimum daily average is 5.0 mg/l (0.2921 grain/gallon) and the minimum acceptable level is 4.0 mg/l (0.2336 grain/gallon)
- (2) A 5°F temperature rise may not cause a resulting stream temperature of greater than 30.6°C (87°F). Also, a maximum hourly temperature change of 1.1°C (2°F) is allowed.
- (3) 500 mg/l (29.2 grain/gallon) is the monthly average. 750 mg/l (43.8 grain/gallon) may never be exceeded.

TABLE 115. AMBIENT AIR QUALITY STANDARDS
OF SOUTH DAKOTA

Constituent	Concentration		Remarks
	Metric	English	
Sulfur Oxides	60 mg/m ³	7.1x10 ⁻⁴ grain/yd ³	A.A.M.
	260 mg/m ³	3.1x10 ⁻³ grain/yd ³	24 hr max*
Particulates	60 mg/m ³	7.1x10 ⁻⁴ grain/yd ³	A.G.M.
	150 mg/m ³	1.8x10 ⁻³ grain/yd ³	24 hr max*
Soil Index	0.66 COH/1000LM 0.20 COH/1000 LF		A.G.M.
Carbon Monoxide	10 mg/m ³	0.12 grain/yd ³	8 hr max*
	15 mg/m ³	0.18 grain/yd ³	1 hr max*
Photochemical Oxidants	125 mg/m ³	1.5x10 ⁻³ grain/yd ³	1 hr max*
Hydrocarbons	125 mg/m ³	1.5x10 ⁻³ grain/yd ³	3 hr max* (1)
Nitrogen Oxides	100 mg/m ³	1.2x10 ⁻³ grain/yd ³	A.A.M.
	250 mg/m ³	2.9x10 ⁻³ grain/yd ³	24 hr max*

(1) Monitored from 6-9 A.M.

Standard Conditions: Temperature = 20°C = 68°F
Pressure = 760 mm Hg = 29.92 in. Hg =
1 atmosphere

TABLE 116. SELECTED SOUTH DAKOTA INDUSTRIAL
EMISSIONS STANDARDS

Fuel Burning Installations

Particulates

0.54 kg/kcal of heat input = 0.30 lb/10⁶ Btu of heat input

Sulfur Oxides

5.4 kg/kcal of heat input = 3.0 lb/10⁶ Btu of heat input

Nitrogen Oxides

0.36 kg/kcal of heat input = 0.2 lb/10⁶ Btu of heat input

General Process Industries

Particulates

$$E = 55.0 p^{0.11} - 40$$

where E = rate of emission in lb/hr

P = process weight rate in ton/hr

TABLE 117. APPLICABLE WATER QUALITY STANDARDS OF SOUTH DAKOTA

Parameter	Concentration		Water Use	Remarks
	Metric	English		
Total Dissolved Solids	1000 mg/l 2000 mg/l	58.4 grain/gal 116.8 grain/gal	Domestic Supply Industrial Supply	
Nitrates	10 mg/l	0.5841 grain/gal	Domestic Supply	As N
Nitrates	45 mg/l	2.6285 grain/gal	Domestic Supply	As NO ₃
Ammonia	0.6 mg/l	0.0350 grain/gal	Domestic Supply	
Chlorides (1)	100 mg/l	5.84 grain/gal	Domestic Supply	
Cyanides (total)	0.02 mg/l	0.0012 grain/gal	Domestic Supply	
Cyanides (free)	0.005 mg/l	2.92 x 10 ⁻⁴ grain/gal	Domestic Supply	
Dissolved Oxygen	6.0 mg/l	0.3505 grain/gal	All	minimum concentration
Dissolved Oxygen	7.0 mg/l	0.4089 grain/gal	Cold	Spawning season
Hydrogen Sulfide	0.002 mg/l	1.17 x 10 ⁻⁴ grain/gal	Water	
Suspended Solids	30 mg/l	1.75 grain/gal	Fish	
Total Iron	0.2 mg/l	0.0117 grain/gal	Propagation	
Temperature	18.3°C	65°F		
Turbidity		10JTU		

(1) Additionally total chlorine is limited to 0.2 mg/l (0.0117 grain/gal).

South Dakota solid waste regulations, with regard to operations, are similar to those of the states previously mentioned. Of greater interest are the requirements pertaining to site locations. Landfills are not permitted within 1,000 feet of any lake or pond, or within 300 feet of any stream or river. Also, a minimum of six feet between waste and the groundwater table must be preserved. Such requirements, promulgated specifically to prevent leaching to groundwater, may provide an applicable basis for future regulatory control of disposal of SRC solid wastes.

TEXAS (53)

All national primary and secondary ambient air quality standards are applicable in Texas. An additional ambient standard for inorganic fluoride compounds, specifically hydrogen fluoride gas, has also been promulgated. This standard, along with net ground level concentrations for applicable compounds, is presented in Table 118. Emissions rates for particulates and sulfur dioxide have been promulgated. Both are functions of effective stack height. Additional emission concentration limits for particulates, sulfur dioxide, and nitrogen oxides in fossil fuel burning steam generators are also presented in Table 118. Visibility requirements prohibit exceeding 20 percent opacity, 15 percent for stationary flues with total flow rates exceeding 100,000 acfm. These opacity limits are for five minute periods and do not include opacity resulting from uncombined water mists.

Texas water standards consist of three parts: general criteria, numerical criteria and water uses. The latter two are highly stream-specific, similar to the Pennsylvania legislation. Water quality parameters and uses for the San Antonio River Basin are shown in Table 119. It should be noted that Texas has one of the warmest climates among those states considered. Natural water temperatures may exceed 96°F. For this reason the 90 degree maximum temperature suggested by the National Technical Advisory Committee does not apply. A maximum temperature increase of 3°F (1.7°C) is permitted for fresh waters, 5°F (2.8°C) for saline waters.

TABLE 118. TEXAS AIR REGULATIONS

Ambient Air Quality Standards for Hydrogen Fluoride

4.5 ppb 12 hr max
 3.5 ppb 24 hr max
 2.0 ppb 7 day max
 1.0 ppb 30 day max

Net Ground Level Concentrations for Applicable Emissions

Constituent	Concentration		Remarks
Hydrogen Sulfide (1)	0.08 ppm		30 min max
	0.12 ppm		30 min max
	Metric ($\mu\text{g}/\text{m}^3$)	English (grain/ yd^3)	
Sulfuric Acid	15	1.8×10^{-4}	24 hr max
	50	5.9×10^{-4}	1 hr max (2)
	100	1.2×10^{-3}	max allowed
Particulates	100	1.2×10^{-3}	5 hr max
	200	2.4×10^{-3}	3 hr max
	400	4.7×10^{-3}	1 hr max

- (1) The first value is applicable only when residential areas are downwind of the source of emissions.
- (2) Denotes that the maximum value is not to be exceeded more than once per 24 hour period.

TABLE 118. TEXAS AIR REGULATIONS (Continued)

Emissions Limits for Fuel Burning Steam Generators (3)

Constituent	Concentration		Remarks
	Metric	English	
Particulates	0.54 kg/10 ⁶ kcal	0.3 lb/10 ⁶ Btu	24 hr max (4)
	0.18 kg/10 ⁶ kcal	0.1 lb/10 ⁶ Btu	2 hr max (5)
Sulfur Dioxide	5.40 kg/10 ⁶ kcal	3.0 lb/10 ⁶ Btu	
Nitrogen Oxides	1.26 kg/10 ⁶ kcal	0.7 lb/10 ⁶ Btu	2 hr max (6)
	0.90 kg/10 ⁶ kcal	0.5 lb/10 ⁶ Btu	2 hr max
	0.45 kg/10 ⁶ kcal	0.25 lb/10 ⁶ Btu	2 hr max

(3) applicable for heat inputs greater than 2500 million Btu/hr.

(4) solid fuel burners

(5) gas and liquid fuel burners

(6) standards apply to opposed fire, front fired, tangential fired-steam generators, respectively.

TABLE 119. WATER USES AND QUALITY CRITERIA FOR THE
SAN ANTONIO RIVER BASIN

Water Use/Quality Parameter	1	2	3	4	5
Contact Recreation	N	0	U	U	U
Non-Contact Recreation	U	U	U	U	U
Fish and Wildlife	U	U	U	U	U
Domestic Supply	U	U	U	U	U
Chlorides, mg/l	200	200	40	120	50
Chlorides grain/gal	11.7	11.7	2.3	7.0	2.9
Sulfates, mg/l	150	300	75	120	75
Sulfates grain/gal	8.8	17.5	4.4	7.0	4.4
Total Dissolved Solids, mg/l	700	900	400	700	400
Total Dissolved Solids, grains/gal	40.9	52.6	23.4	40.9	23.4
pH range	6.5-8.5	7.0-9.0	7.0-9.0	7.0-9.0	7.0-9.0
Temperature, °C	32	32	32	32	32
Temperature, °F	90	90	90	90	90
Dissolved oxygen, mg/l	5.0	5.0	5.0	5.0	5.0
Dissolved oxygen, grain/gal	0.29	0.29	0.29	0.29	0.29

N not currently useable

0 not currently useable, quality to be improved

U useable for given water use

- (1) San Antonio River
- (2) Cibolo Creek (Section 1)
- (3) Cibolo Creek (Section 2)
- (4) Medina River (Section 1)
- (5) Medina River (Section 2)
- (6) Medina Lake
- (7) Medina River (Section 3)
- (8) Leon Creek (Section 1)
- (9) Leon Creek (Section 2)

TABLE 119. WATER USES AND QUALITY CRITERIA FOR THE
SAN ANTONIO RIVER BASIN (Continued)

Water Use/Quality Parameter	6	7	8	9
Contact Recreation	U	U	U	U
Non-Contact Recreation	U	U	U	U
Fish and Wildlife	U	U	U	U
Domestic Supply	U	U	U	U
Chlorides, mg/l	50	40	120	40
Chlorides grain/gal	2.9	2.3	7.0	2.3
Sulfates, mg/l	75	100	120	75
Sulfates grain/gal	4.4	5.8	7.0	4.4
Total Dissolved Solids, mg/l	400	400	700	400
Total Dissolved Solids, grains/gal	23.4	23.4	40.9	23.4
pH range	7.0-9.0	7.0-9.0	7.0-9.0	7.0-9.0
Temperature, °C	31	31	35	35
Temperature, °F	88	88	95	95
Dissolved oxygen, mg/l	5.0	5.0	5.0	5.0
Dissolved oxygen, grain/gal	0.29	0.29	0.29	0.29

Three classifications of industrial solid waste exist. These can be characterized as hazardous, naturally decomposable organics and inorganics, and inert materials. All plans and specifications relevant to site selection, design and operation of industrial waste disposal operations must be reviewed and approved by appropriate state authorities.

UTAH (53)

Utah has no ambient air or new source standards at this time. Current federal standards are applicable. The Utah Air Conservation Regulations note that the Utah Air Conservation Committee and the State Board of Health do not agree with most of the federal standards. There is no indication of the types of standards these organizations favor. Future legislation will have to answer that question. State emissions standards have been set for particulates requiring 85 percent control. Sulfur emissions must meet federal ambient and new source standards.

Stream quality criteria are dependent upon stream classification. Class "A" waters are to be suitable without pretreating for a variety of uses including domestic water supply and propagation of fish and wildlife. Such waters are to be free from organic substances measured by biochemical oxygen demand. A pH range of 6.5 to 8.5 is to be maintained. Physical characteristics and chemical concentration standards are the same as prescribed by "Public Health Service Drinking Water Standards, 1962." These are described in Table 120. All solid waste disposal operations must meet approval of the Utah State Division of Health.

WEST VIRGINIA (53)

A brief review of West Virginia state air laws provides a good idea of the relative importance of the coal mining industry there. Air pollution control legislation has been promulgated for refuse disposal, preparation and handling operations. These regulations and particulate limits for manufacturing process operations are detailed in Table 126. Ambient air quality standards are detailed in Table 122.

Water quality criteria, based on water use similar to the Pennsylvania criteria is highlighted in Table 123. Criteria for the Gauley River and tributaries was chosen for presentation due to its acceptability for all water use classifications.

TABLE 120. WATER CRITERIA FOR CLASS "A" UTAH WATERS
(FROM PUBLIC HEALTH SERVICE DRINKING WATER STANDARDS, 1962)

Turbidity: 5 JTU

Chemical Constituent	Concentration	
	Metric (mg/l)	English (grain/gal)
Arsenic	0.01	5.84×10^{-4}
Chlorides	250	14.6
Copper	1.0	0.0584
Cyanide	0.01	5.84×10^{-4}
Fluoride (1)	1.7	0.0993
Iron	0.3	0.0175
Manganese	0.05	0.0029
Nitrates	45	2.63
Phenols	0.001	5.84×10^{-5}
Sulfates	250	14.6
Total Dissolved Solids	500	29.2
Zinc	5.0	0.2921

(1) Fluoride concentrations is temperature dependent, the given value being the maximum allowed at temperatures below 10°C (50°F).

TABLE 121. APPLICABLE AIR POLLUTION REGULATIONS
IN WEST VIRGINIA

Coal Preparation, Drying and Handling

Particulates - for volumetric flow rates greater than 14,200 scm/m (500,000 scf/min.), the allowable emission rate is 0.18 gm/scm (0.08 grain/scf).

Manufacturing Process Operations

Particulates - for process weight rates exceeding 45,500 kg/hr (100,000 lb/hr) the allowable emission rate is 9.6 kg/hr (21.2 lb/hr).

Smoke - No smoke darker than No. 1 on the Ringelmann Smoke Chart is permitted. No smoke darker than No. 2 on the Ringelmann Smoke Chart is permitted for more than five minutes in any sixty minute period.

TABLE 122. WEST VIRGINIA AIR QUALITY STANDARDS

Constituent	Concentration		Remarks
	Metric	English	
Sulfur Dioxide			
primary	80 mg/m ³	9.4x10 ⁻⁴ grain/gal	A.A.M.
	365 mg/m ³	4.3x10 ⁻³ grain/gal	24 hr max*
secondary	1300 mg/m ³	1.5x10 ⁻² grain/gal	3 hr max*
Particulates			
primary	75 mg/m ³	8.8x10 ⁻⁴ grain/gal	A.G.M.
	260 mg/m ³	3.1x10 ⁻³ grain/gal	24 hr max*
secondary	60 mg/m ³	7.1x10 ⁻⁴ grain/gal	A.G.M.
	150 mg/m ³	1.8x10 ⁻³ grain/gal	24 hr max*
Carbon Monoxide			
standard	10 mg/m ³	0.12 grain/gal	8 hr max*
	40 mg/m ³	0.47 grain/gal	1 hr max*
Photochemical Oxidants			
standard	160 mg/m ³	1.9x10 ⁻³ grain/gal	1 hr max*
Non-Methane Hydrocarbons	160 mg/m ³	1.9x10 ⁻³ grain/gal	3 hr max* (6-9 A.M.)

Standard Conditions: Temperature = 25°C - 77°F
 Pressure = 760 mmHg = 29.92 in Hg = 1 atmosphere

TABLE 123. WATER QUALITY CRITERIA FOR THE GAULEY RIVER
AND TRIBUTARIES IN WEST VIRGINIA

Dissolved Oxygen: never less than 5.0 mg/l = 0.2921 grain/gallon
 pH Range : 6.0 - 8.5
 Temperature: Maximum increase 2.8°C = 5°F
 Maximum Temperature
 27°C = 81°F (May-November)
 23°C = 73°F (December-April)

Chemical Constituent	Maximum Concentration	
	Metric (mg/l)	English (grain/gal)
Arsenic	0.01	5.84×10^{-4}
Barium	0.50	0.0292
Cadmium	0.01	5.84×10^{-4}
Chloride	100	5.84
Chromium (hexavalent)	0.05	0.0029
Cyanide	0.025	0.0015
Fluoride	1.0	0.0584
Lead	0.05	0.0029
Nitrates	45	2.63
Phenol	0.001	5.84×10^{-5}
Selenium	0.01	5.84×10^{-4}
Silver	0.05	0.0029

West Virginia has three solid waste classifications, analagous to those previously described in the Texas solid waste laws. Requirements for disposal of hazardous wastes shall be determined on a case-by-case basis. Class II decomposable wastes are subject to six inches of daily cover and two feet of final cover.

WYOMING (53)

Table 124 defines the state ambient air quality standards. Emissions standards, primarily applicable to fossil fuel burning installations, are presented in Table 125. Wyoming has additional regulations governing hydrocarbon storage and handling. Waste disposal combustion systems for vapor blowdown or emergency situations are to be burned in smokeless flares. Pressurized tanks, floating roofs, or vapor recovery systems are required for storage of hydrocarbons.

Water quality standards which may affect future commercial SRC operations are summarized in Table 126. Wyoming waters are classified as having potential to support game fish (Class I), potential to support non-game fish (Class II), or as not having the potential to support fish (Class III). In addition, waters designated a part of the public water supply must meet the most recent Federal Drinking Water Standards. These are described in Table 127.

The Wyoming Department of Environmental Quality reviews construction and operating plans of all industrial or hazardous waste disposal operations. Industrial waste disposal sites shall not be located in areas of low population density, land use value and groundwater leaching potential. Monitoring wells must be installed prior to commencement of operations. Disposal sites may not be located near drinking water supply sources. It is suggested, but not required, that disposal sites with impermeable soil be selected.

TABLE 124. WYOMING AMBIENT AIR STANDARDS

Constituent	Concentration		Remarks
	Metric	English	
Particulates	60 mg/m ³	7.1x10 ⁻⁴ grain/gal	A.G.M.
	150 mg/m ³	1.8x10 ⁻³ grain/gal	24 hr max*
Soiling Index	1.3 COH/1000	0.4 COH/1000 LF	A.G.M.
Total Settleable	5 g/m ² /month	59 grain/yd ² /month	(1)
Particulates	10 g/m ² /month	118 grain/yd ² /month	
Sulfur Oxides	60 mg/m ³	7.1x10 ⁻⁴ grain/gal	A.A.M.
	260 mg/m ³	3.1x10 ⁻³ grain/gal	24 hr max*
	1300 mg/m ³	1.5x10 ⁻² grain/gal	3 hr max*
Hydrogen Sulfide	70 mg/m ³	8.3x10 ⁻⁴ grain/gal	1/2 hr max (2)
	40 mg/m ³	4.7x10 ⁻³ grain/gal	1 hr max*
Photochemical Oxidants	160 mg/m ³	1.9x10 ⁻³ grain/gal	1 hr max*
Hydrocarbons	160 mg/m ³	1.9x10 ⁻³ grain/gal	3 hr max* (3)
Nitrogen Oxides	100 mg/m ³	1.2x10 ⁻³ grain/gal	A.A.M.
Fluorides	1 ppb		24 hr max
Carbon Monoxide	10 mg/m ³	0.12 grain/gal	8 hr max*
	40 mg/m ³	0.47 grain/gal	1 hr max*

Standard Conditions: Temperature = 21°C = 70°F
 Pressure = 760 mmHg = 29.92 in.Hg = 1 atmosphere

- (1) Values given include 1.7 g/m²/month (20.1 grain/yd²/month)
 background settled particulates
- (2) Hydrogen sulfide values are not to be exceeded more than twice per year.
- (3) Monitored 6-9 A.M.

TABLE 125. APPLICABLE WYOMING EMISSIONS REGULATIONS

New Fuel Burning Equipment - Sulfur Dioxide

$$0.36 \text{ kg}/10^6 \text{ Kcal input} = 0.20 \text{ lb}/10^6 \text{ Btu input}$$

(applicable to coal burners)

New Fuel Burning Equipment - Nitrogen Oxides

$$1.26 \text{ kg}/10^6 \text{ Kcal input} = 0.70 \text{ lb}/10^6 \text{ Btu input}$$

(applicable to non-lignite coal burners)

Stationary Sources - Carbon Monoxide Requirement

Stack gases shall be treated by direct flame after burner as required to prevent exceeding ambient standards.

Stationary Sources - Hydrogen Sulfide Requirement

Gases containing hydrogen sulfide shall be vented, incinerated, or flared as necessary to prevent exceeding ambient standards.

New Sources - Particulates

$$E = 17.31 P^{0.16} \text{ (for } P \geq 30 \text{ tons/hr)}$$

where E = maximum allowable rate of emissions in lb/hr

P = process weight rate in tons/hr

For a 50,000 bbl/day SRC plant

$$E = 17.31 \frac{22,000 \text{ ton/day}}{(24 \text{ hr/day})}^{0.16}$$

$$E = 17.31 (917)^{0.16} = 51.6 \text{ lb/hr}$$

TABLE 126. WYOMING WATER QUALITY STANDARDS

Parameter	Concentration Limits		Remarks
Settleable Solids	free from		
Floating Solids	free from		
Toxic Materials	free from		
Turbidity	10 JTU increase		
pH Range	6.5 - 8.5		
Total Gas Pressure	Not to exceed 110% (of atmospheric pressure)		
	<u>Metric</u>	<u>English</u>	
Dissolved Oxygen	6 mg/l	0.3505 grain/gal	Class I water
	5 mg/l	0.2921 grain/gal	Class II water
Oil/Grease	10 mg/l	0.5841 grain/gal	

Temperature

The maximum temperature allowed is 26°C (78°F) for streams supporting cold water fish and 32°C (90°F) for streams supporting warm water fish.

The maximum allowable temperature increase is dependent upon natural water temperature. For streams with maximum natural temperatures of 20°C (68°F) or less the maximum allowable temperature increase is 1.1°C (2°F). For streams with maximum natural temperatures exceeding 20°C (68°F), the maximum allowable temperature increase is 2.2°C (4°F).

TABLE 127. EPA NATIONAL INTERIM PRIMARY
DRINKING WATER STANDARDS

Constituent	Maximum Concentration	
	Metric (mg/l)	English (grain/gallon)
Arsenic	0.05	0.0029
Barium	1.0	0.0584
Cadmium	0.01	5.84×10^{-4}
Chromium	0.05	2.92
Lead	0.05	0.0029
Mercury	0.002	1.17×10^{-4}
Nitrate (as N)	10	0.5841
Selenium	0.01	5.84×10^{-4}
Silver	0.05	0.0029

	Temperature	Concentration	Temperature	Concentration
	(°C)	(mg/l)	(°F)	(grain/gal)
Fluorine	12.1 & below	2.4	53.7 & below	0.1402
	12.2 - 14.6	2.2	53.8 - 58.3	0.1285
	14.7 - 17.7	2.0	58.4 - 63.8	0.1168
	17.8 - 21.4	1.8	63.9 - 70.6	0.1051
	21.5 - 26.2	1.6	70.7 - 79.2	0.0935
	26.3 - 32.5	1.4	79.3 - 90.5	0.0818